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Santa Clara Valley Water District

and the Silicon Valley Pollution Prevention Center

District Hydroelectric Power Potential

March 2002

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SALAS O'BRIEN ENGINEERS, INC.
305 S 11th STREET • SAN JOSÉ, CA 95112 • (408) 282-1500 • FAX: (408) 297-2995
498 FOAM STREET • MONTEREY, CA 93940 • (408) 657-0251

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This report brief was developed in a format such that it provides a basis and re-Discovery Phase for short and long term hydropower production at various District Sites.

All observations, calculations, analysis, cost estimates and recommendations were developed by experienced professionals and/or licensed engineers and are based on generally accepted principles and general market conditions. However, because this is the Discovery Phase of the project, all calculations and cost estimates are "budget grade" in nature. Likewise all results and conclusions are made with an eye towards the eventual development of a more detailed feasibility analysis and conceptual design corresponding to the specific recommendations.

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Executive Summary

Executive Briefing

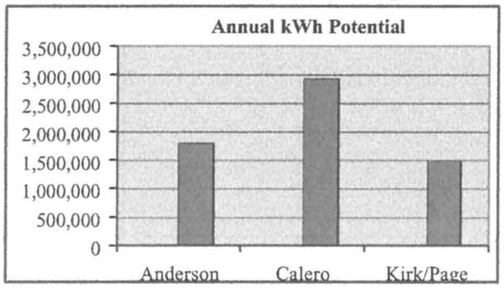
2002 Update of Hydroelectric Power Potential

Background: Since 1978 the Water District has contemplated hydroelectric power production in as many as 9 locations. In only one location, Anderson Dam, has a hydro plant actually been installed and operated. This Report re-visits 3 sites as a framework for defining current opportunities, benefits and flaws associated with renewed attention to hydro power production.

Timing: California, as a state, is still recovering from its flawed experiment with deregulation and a 9-month "energy crisis" (11/00 – 8/01). In the wake of those events the question arises: *"How can the Water District take advantage of its hydroelectric power potential"*.

Major Parameters: Seven separate issues were considered relative to hydropower opportunities at the 3 sites. In addition all nine sites were re-visited relative to past discussions of potential. Information relating to the following seven parameters is available, by tab, in the text of this report. These parameters are:

1. Physical Feasibility
2. Coincident Energy Demand
3. Transmission Options
4. Revenue Options
5. Incentive & Funding Options
6. Partnership Options
7. Legal & Regulatory Options



Hydropower at the 3 sites varies in potential (to over 6,000,000 kWh/year).

Benefits: In addition to income related benefits from the hydro plant(s), there are a number of other potential benefits including:

1. **Locally produced renewable energy**, representing elements of both sustainable & pollution free generation. Calero alone would displace over 11 million lbs of CO2 and 100,000 lbs of SOx. Although small, this is one step closer to clean California energy independence.
2. **Increased security & reliability** of treatment plants, pumping plants and other facilities supplied by District-owned generation and transmission facilities.
3. **Reduced demand on the western electric grid**: become part of the solution to future energy shortages; similar to the rationale for developing locally recycled water to give the District more reliability/independence when shortages/outages of state/federal water projects occur.
4. **Existing dams** (or diverters) will have minimal environmental impact (may not require EIR).

Recommendations, Savings & Payback: Current opportunities and market conditions suggest 4 tasks:

Task Plan	**Cost**	**Income**[1]	**Payback**
1) Revalidate/upgrade the Calero feasibility study; and develop an interconnection (or bypass) grid connect to Santa Teresa. ***FY02/03 Budget: $85,000***	$2,227,500	$412,350	5.4 years
2) Evaluate optimization strategies/metrics for the existing plant at Anderson. ***FY02/03 Budget: $40,000***	$95,000	$68,000	1.5 years
3) Defer Kirk/Page and all remaining sites from further consideration until after 2003. ***FY02/03 Budget: $0***	*see footnote*[2]	n/a	n/a
4) Investigate becoming a municipal utility to open up revenue options. ***FY02/03 Budget: $25,000***	$125,000	n/a	n/a

Other major water utilities in California (LADWP, Hetch Hetchy, Modesto ID) have been successful combining both water and electricity generation to assure that power is available for operations of their water treatment and delivery system(s). Task plans 1 & 2, above, will allow for a deliberate, managed but conservative expansion of the District's portfolio of services.

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[1] Cash income only, includes maintenance and reporting costs, does not include benefits identified above.

[2] Current market volatility and uncertainty suggests that it is best to focus on high return, low risk projects (Task Plan items 1 & 2) until the California market and utility situation stabilizes. Feedback from tasks 1 and 2 will provide insight into "timing" of future hydro activity.

Report

THIS REPORT has been developed in a format that provides high-level summaries and background relative to the variables reviewed (and framed against the many prior reports). As stated in the Executive Summary, 7 separate issues were reviewed relative to current and past analysis at 3 major hydro sites. Tabs, which follow, correspond to the 7 issues. Note that in the summary below, the "signal" indicates the influence of the current market conditions.

Signal	Issues Summary	Benefits and/or Flaws
YES	**1) Physical Feasibility** In addition to the 940 installed kW at Anderson, there is potential for 550 kW at Calero and 650kW at Kirk/Page. In summary, the District potential is: Installed (Anderson) 940 *(760e)* + Calero and Kirk/Page 1,200 + Remaining 6 sites 2,531	• No significant physical limitations. • 4.7 MW of gross potential • Flow requirements result in power not fully dispatchable
NO	**2) Coincident Energy Demands.** "Best" income scenario(s) involve "net metering" (i.e. local-and-coincident use of power as generated). However, in 2 of 3 sites there is a poor or non-existent relationship between local energy demand, and hydropower production.	• No local or adjacent use of power by the District. • Potential export is low in 2 of 3 sites. Kirk/Page NFS[1]
YES	**3) Transmission Options:** The Pubic Utility Commission's Rule 21 defines interconnection standards (i.e. for connection to the electric grid). Although the District's existing rights-of-way and the generally low energy from the hydro plant facilitate relatively easy access to the grid, the interconnection process (and associated expense) requires significant cost and coordination with PG&E.	• Rights of way and low voltage facilitates connection. • Connection rules may not be conducive to relatively low capacities.
WATCH	**4) Revenue Options:** Had California's deregulation not been suspended, there would be potential for as much as $2.8million per year in current revenue (or net metering). However, current market conditions and regulations are conducive only to low relative income. Installed (Anderson) $138,000 *to $830,000 annually* + Calero and Kirk/Page $160,000 *to $1,100,000 ' '* + Remaining 6 sites $176,000 *micro-hydro possible*	• There is significant income potential under a "merchant plant" scenario • Anderson's contract and the current "suspended" market provide low $ potential
LOBBY	**5) Incentives & Funding Options:** At both the State & National level there is significant interest in truly renewable resources. Because these dams are already built and/or the hydro potential can be garnered from modulating valves in the pipeline, there is significant potential for future funding. However, no current incentives exist.	• Significant interest and national need • Low relative capacity • No current funding
WATCH	**6) Partnership Options:** Given a robust market for power, the myriad of partnering opportunities include: (1) PG&E (constrained transmission sector); (2) Merchant Power Co. (Calpine, et. al), (3) Local Municipals (Silicon Valley Power, or City of Palo Alto Muni); (4) The State (California Power Authority).	• A myriad of partnering opportunities exist. • Less than 6MW is too little for most power "players" • Today's market is in a state of suspension and confusion
NFS	**7) Legal and Regulatory Issues:** Although small hydro sites can receive exemption from FERC licensing, current legal contracts and dam safety requirements may preclude simple & profitable operation.	• FERC exemptions available[2] • Contracts and reporting requirements significant

This Report concludes that, in spite of reasonable potential for dependable and renewable power, current market conditions suggest that future activities are best broken into three "action" plans: (1) Move forward on a detailed feasibility study at Calero; (2) Optimize income/revenue metrics at the existing Anderson hydro plant. (3) Defer other sites from further consideration until 2003

For each of the three "actions", a justification and task breakdown follows. This information is followed, in turn, by tabs associated with each issue. Also issued, as the Appendix, is a summary of the many prior reports associated with the hydropower potential at the various District sites.

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[1] Needs further study

[2] Two sites: Calero & Kirk/Page

Phase I - Recommendations for Further Action

Suggested Action	Justification	Tasks
I. Conduct detailed interconnection study and revise existing feasibility study at Calero: **Est. Plant Cost[1]: $2,227,500** **Annual Net Income: $412,350** **Simple Payback: 5.4 years** **Simple Return: 18.5%** **Study Cost (FY02/03): $85,000**	Calero has the highest and best power delivery and production potential relative to the issues discussed in this study (and in prior studies).	• Initiate Rule-21 (grid) connection study. • Develop simultaneous cost/concept(s) for District-owned "connect" to Santa Teresa. • Develop flow vs. kW projections. • Analyze equipment and installation options (diverter vs. dam). • Investigate FERC requirements.
II. Conduct study to optimize existing operation at Anderson: **Estimated Study Cost[2]: $95,000** **Annual Net Income: $68,000** **Simple Payback: 1.5 year** **Simple Return: 100%** **Study Cost (FY02/03): $40,000**	Anderson is currently performing and has an 11-year operating history (performance, income and expenses). Of particular note is that "per CFS" and "income-relative-to-flow" vary significantly from year to year. A viable and expanded power production program can and should take advantage of "lessons learned" at Anderson.	• Obtain full history production, maintenance, operation and flow data. • Review maintenance & utility contract & plan • Investigate physical configuration and operation vs. real-time CFS; link Coyote pumping station configuration options. • Develop realistic "best operational practices" (to maximize income). • Review original FERC exemption request and final ruling.
III. Defer further study on (1) Kirk/Page and (2) the remaining sites mentioned in this report until 2003: **Cost: defer** **Annual Net Income: defer** **Simple Payback: n/a** **Simple Return: future** **Study Cost (FY02/03): $0**	• So. Bay Aqueduct allocations are subject to fluctuations. Likewise, Kirk/Page data, in prior studies, was taken in years of "100% allocation". Thus the potential may be lower than indicated in earlier studies. • California's "suspended" deregulation status suggests caution except in special cases (i.e. see "Action" I & II, above). • Future need for renewables lends itself to potential future rebates/incentives (where none exist today).	• Monitoring the California energy marketplace through PG&E and the Ca. Power Authority. This will involve periodic attendance at conferences and/or State and/or Utility sponsored events relating to distributed generation or renewables. • Consider lobbying the State legislature for laws and incentives that recognize and reward the value of pipeline hydro as a "hidden" renewable resource. • See footnote[3]
IV. Conduct study to evaluate potential benefits of becoming a municipal utility: **Estimated Full Study Cost: $125,000** **Pre-Feasibility Cost (FY02/03): $25,000**	A municipal utility could potentially avoid Rule 21 interconnection revenue limitations and sell directly to energy consumers near District generation facilities.	• Pre-feasibility study to determine potential revenue impact, legal & regulatory flaws and detailed work plan • If feasible, follow-up with full investigation

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[1] This is the estimated cost of the plant (current statement of probable costs).

[2] No modifications are anticipated to the plant (i.e. only considerations and minor modifications relating to operations).

[3] These tasks will "fall out" from the activities in Action 1 and Action 2, so no budget is recommended.

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C. Appendix

Major Section Elements:

This section provides a high-level overview of the general potential of the various sites (under study as well as prior reports). As such, it provides:

1) A summary of the prior reports relating to activities associated with District Hydroelectric Potential.

2) ANDERSON: Prior and "current" capacity and production from the Anderson hydroelectric plant. This plant has been fully operational since 1989 at an installed cost of $2,500 per installed KW.

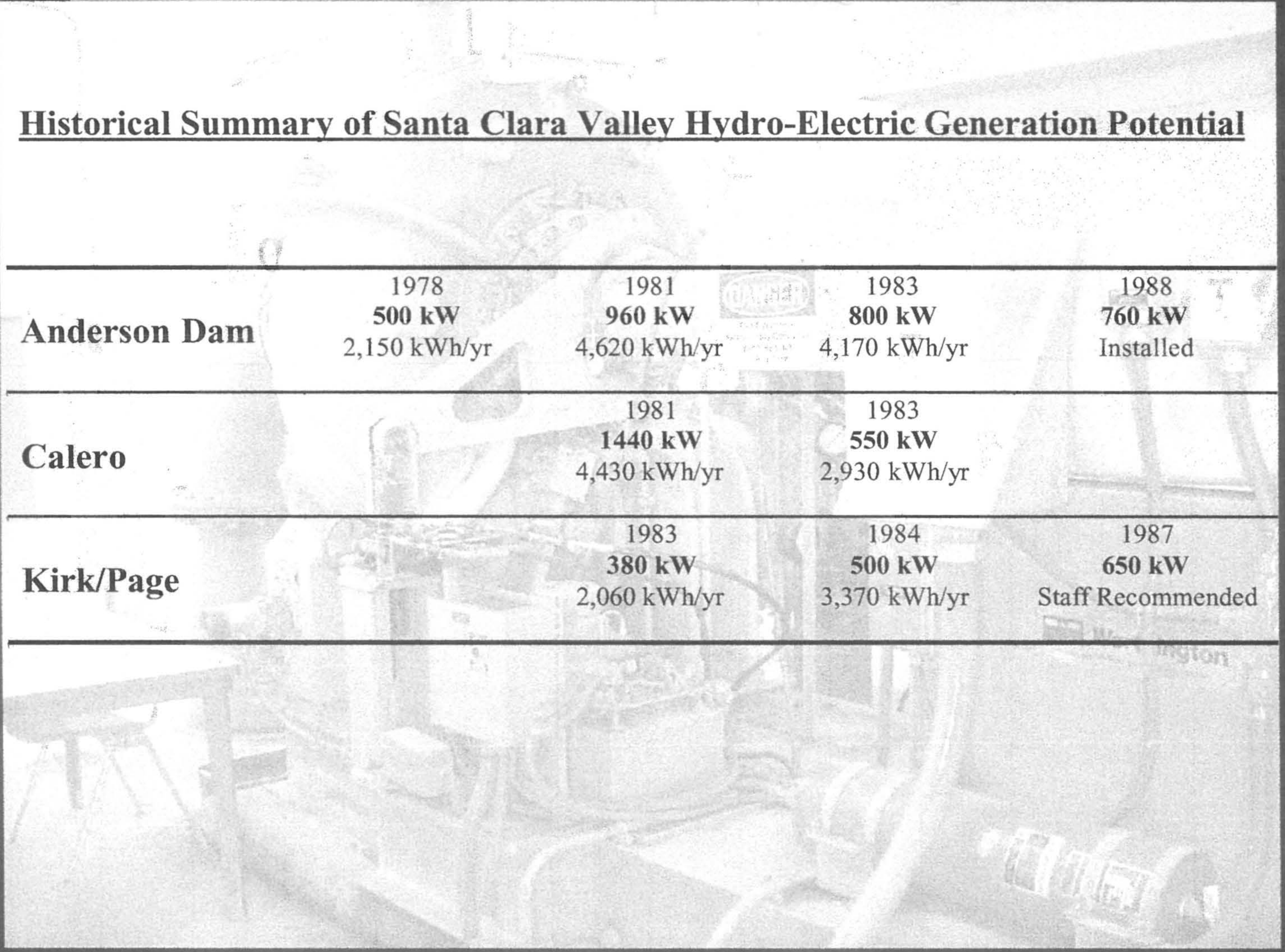
3) CALERO: Actual annual flow and estimated energy production from that flow in 1999-2000. This site has the best generation potential of the three sites studied.

4) KIRK PAGE: Actual annual flow and estimated energy production from that flow in 1999-2000. Due to numerous flow requirements, this site appears to have lowest generation potential and is the least "dispatchable" of the sites.

5) KEY REMAINING SITES: Although out of the scope of this report, the District's information base contains significant insights into hydropower potential at 6 other sites. In some cases, although capacity potential is generally low, technology advances compliment the site opportunity.

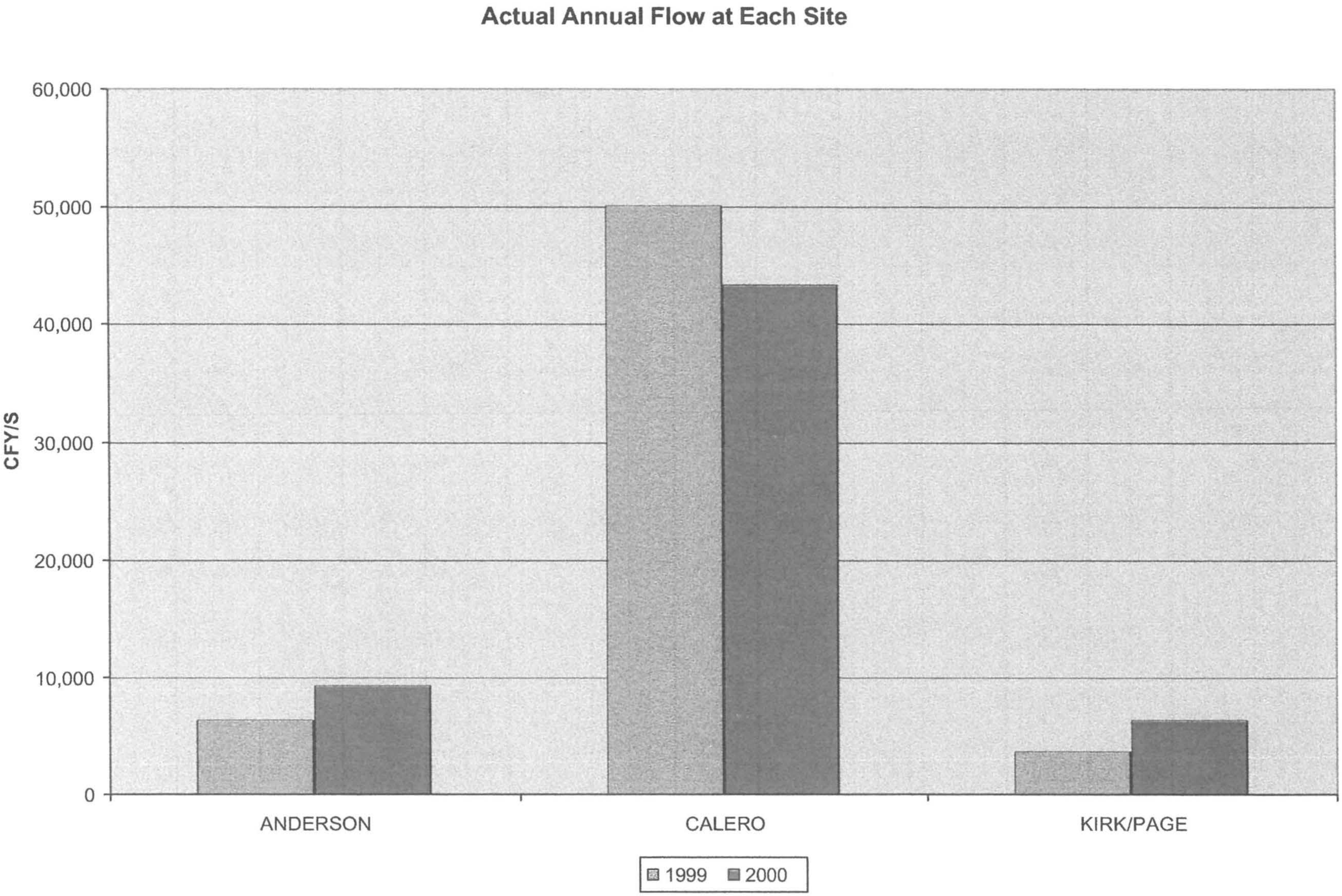
Renewable Power Generation (hydro)

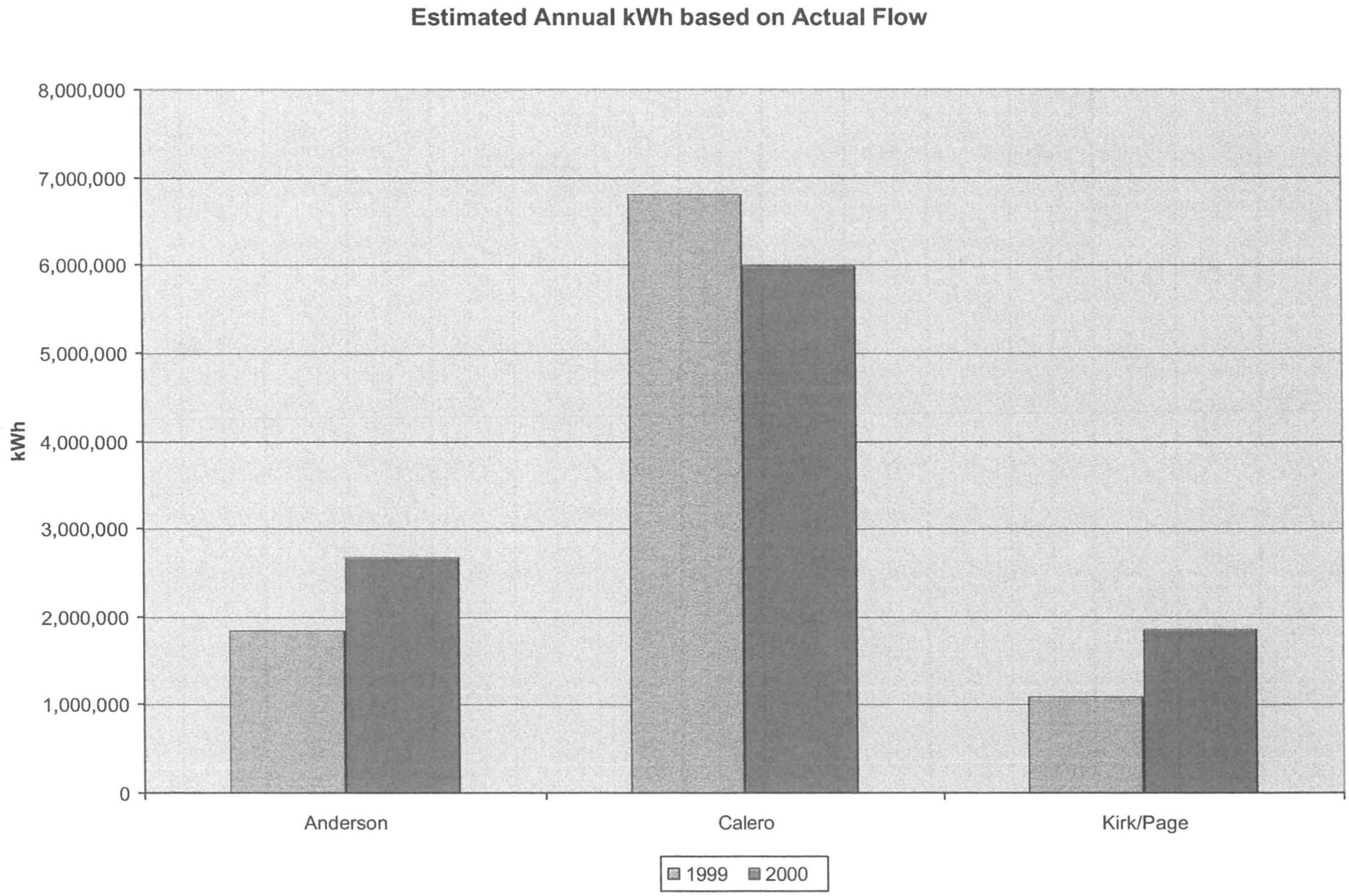
Study Focus: Reviewing 3 of 9 Potential Sites

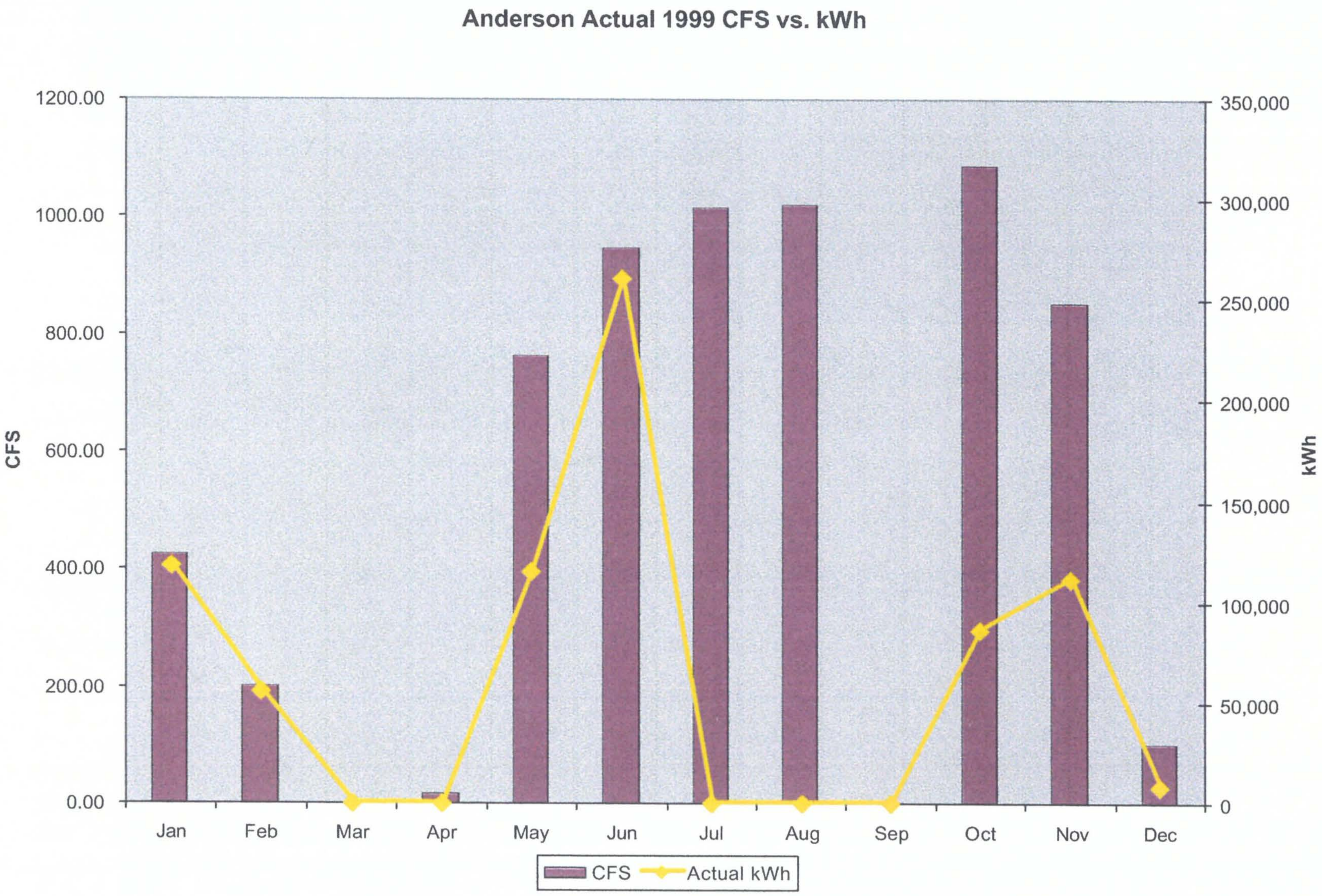


Historical Summary of Santa Clara Valley Hydro-Electric Generation Potential

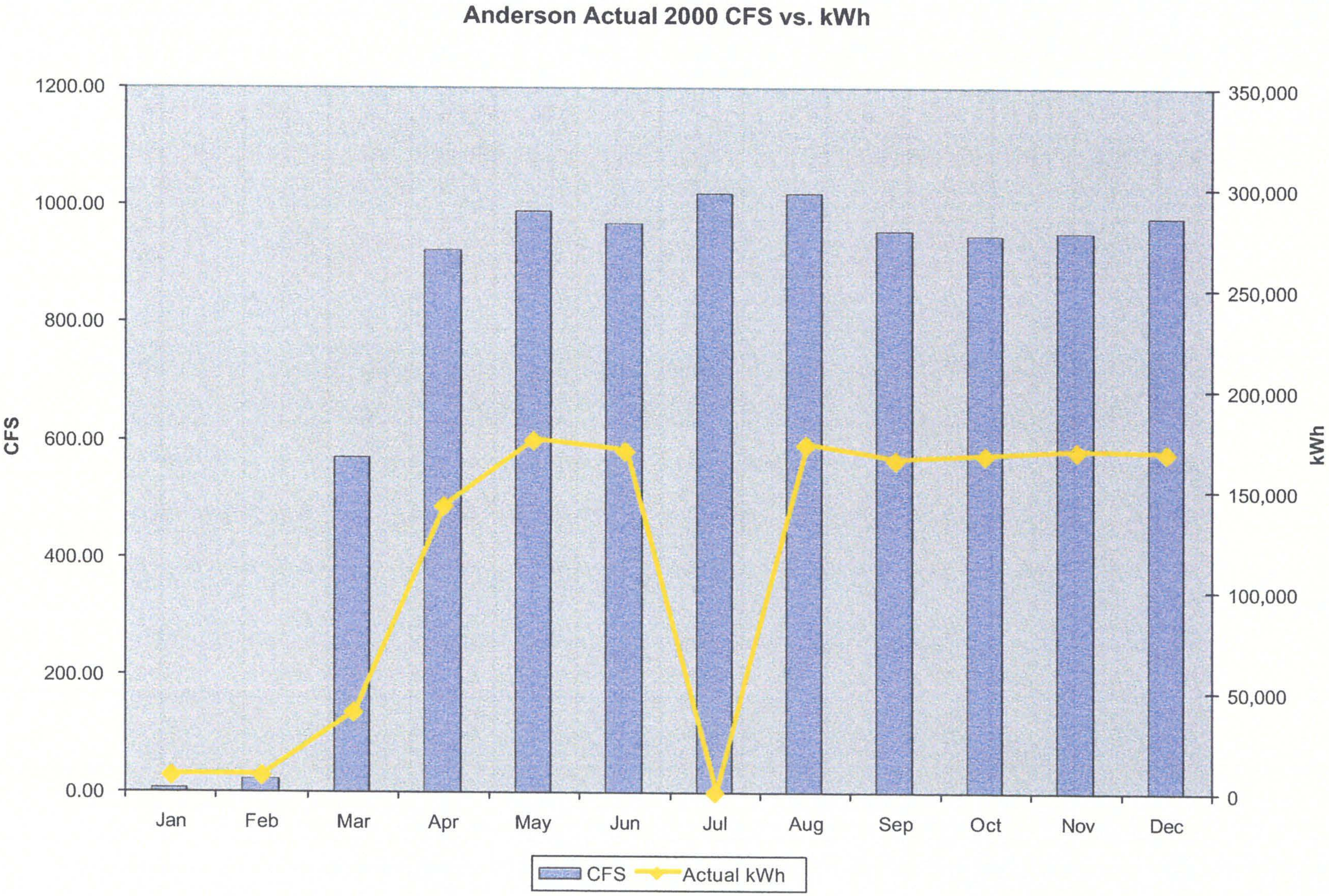
Anderson Dam	1978 **500 kW** 2,150 kWh/yr	1981 **960 kW** 4,620 kWh/yr	1983 **800 kW** 4,170 kWh/yr	1988 **760 kW** Installed
Calero		1981 **1440 kW** 4,430 kWh/yr	1983 **550 kW** 2,930 kWh/yr	
Kirk/Page		1983 **380 kW** 2,060 kWh/yr	1984 **500 kW** 3,370 kWh/yr	1987 **650 kW** Staff Recommended


Actual Annual Flow at Each Site
60,000
50,000
40,000
30,000
20,000
10,000
0
CFY/S
ANDERSON
CALERO
KIRK/PAGE
▨ 1999
■ 2000


Estimated Annual kWh based on Actual Flow
kWh
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
Anderson
Calero
Kirk/Page
1999
2000


Anderson Actual 1999 CFS vs. kWh
1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
CFS
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
kWh
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
CFS
Actual kWh

2000 Anderson Actual



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A. Executive Summary
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Major Section Elements:

It is general knowledge that the most expedient and most profitable means of using District generated power is to take advantage of local net metering[1]. In this way, high cost power (ie. as purchased from PG&E) would be displaced by locally produced hydropower. Unfortunately, "master" net metering, which would allow the production from multiple sites to offset District-wide usage, is not allowed under the current regulatory structure.

It would be possible to sell power to adjacent, non-District users, but none of the sites appear to be close to any major energy demands. Further study of the commercial area near Kirk/Page may be warranted.

1. **The primary District energy users consumed over 13 million kWh in the year 2000. This does not include the many district pumping stations. Therefore, the District could easily use the estimated 10-12 million kWh generated by the three sites studied.**
2. **The cost of the District's energy has been rising, from a low of about 5 cents per kWh in April 2000 ($650,000 annual cost) to a high of close to 10 cents per kWh in August 2001 ($1,300,000 annual cost).**

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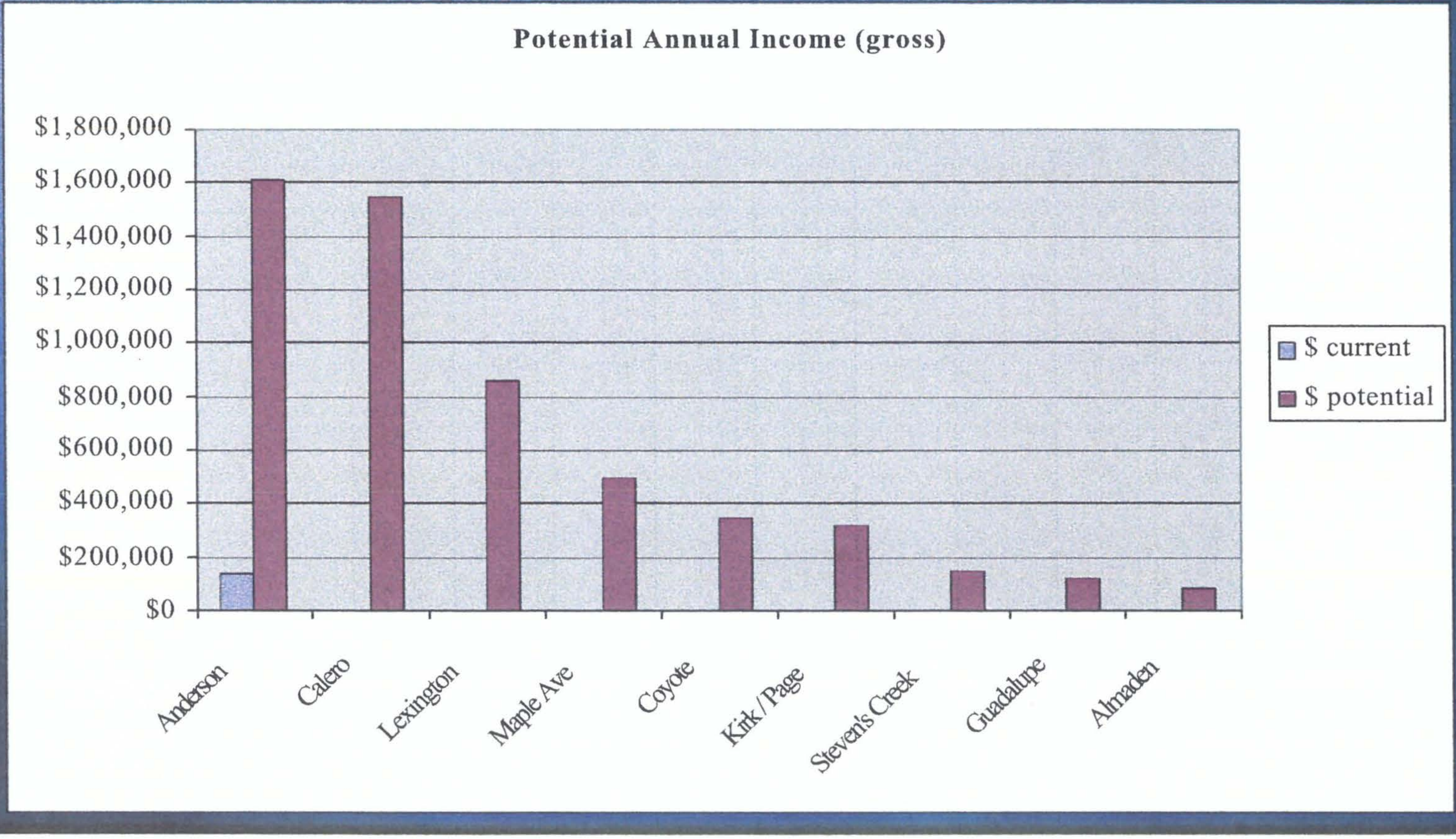
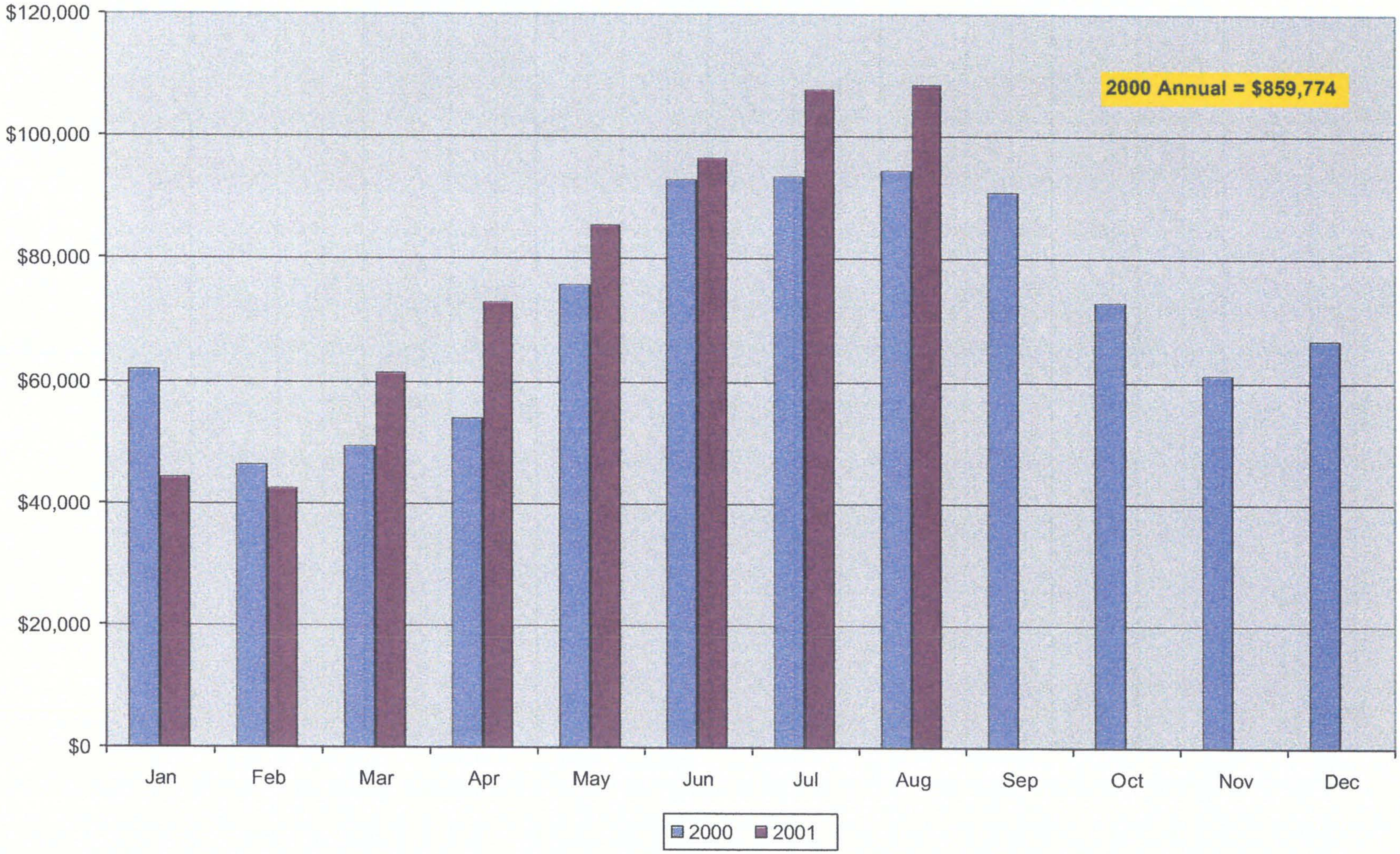
[1] Net metering measures the difference between the electricity purchased from PG&E and the electricity you produce using your own generating equipment. The electric meter keeps track of this "net" difference as you both generate electricity and take electricity from the electric grid.

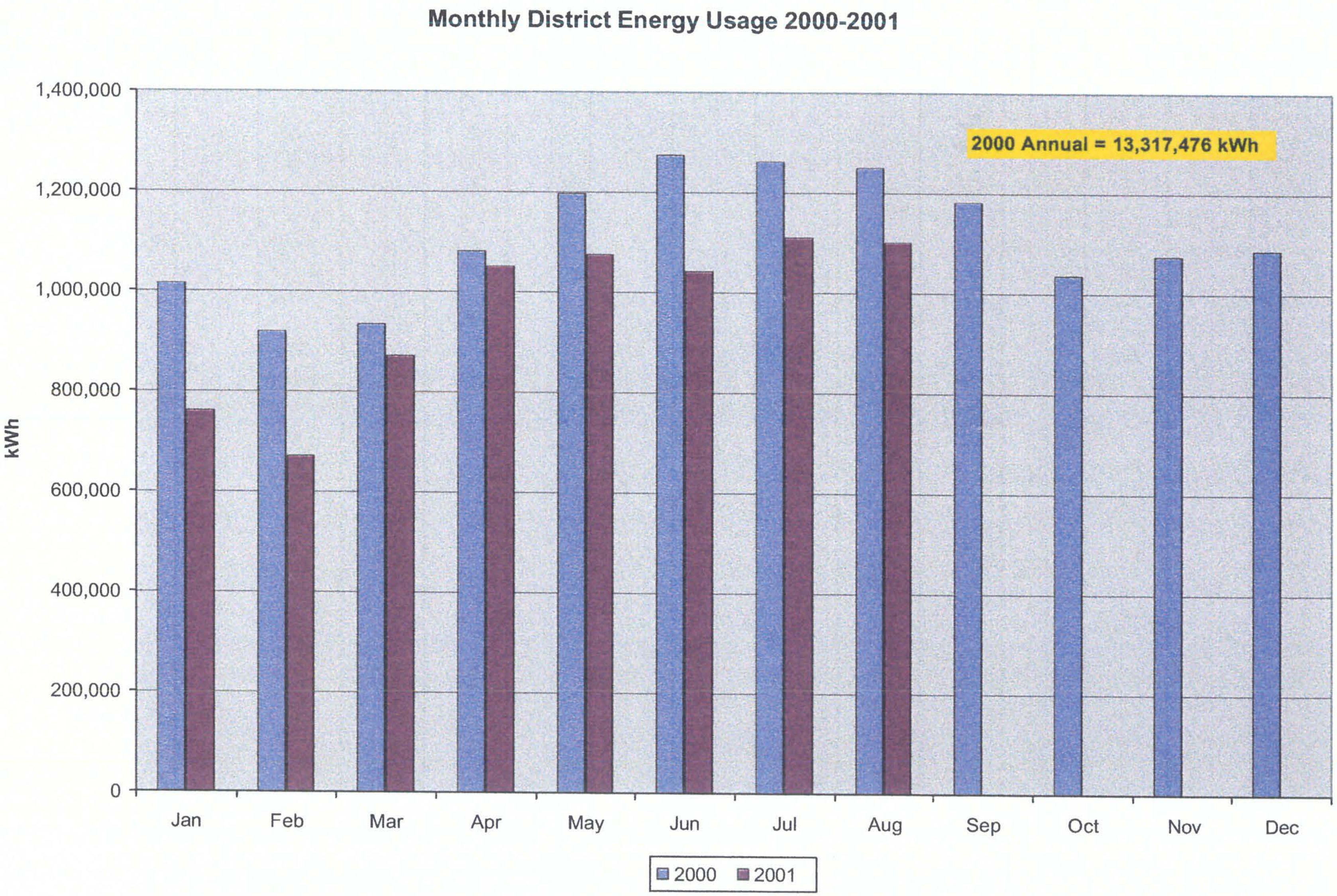
Renewable Power Generation (hydro)
. . . as a part of a the SCWD Portfolio

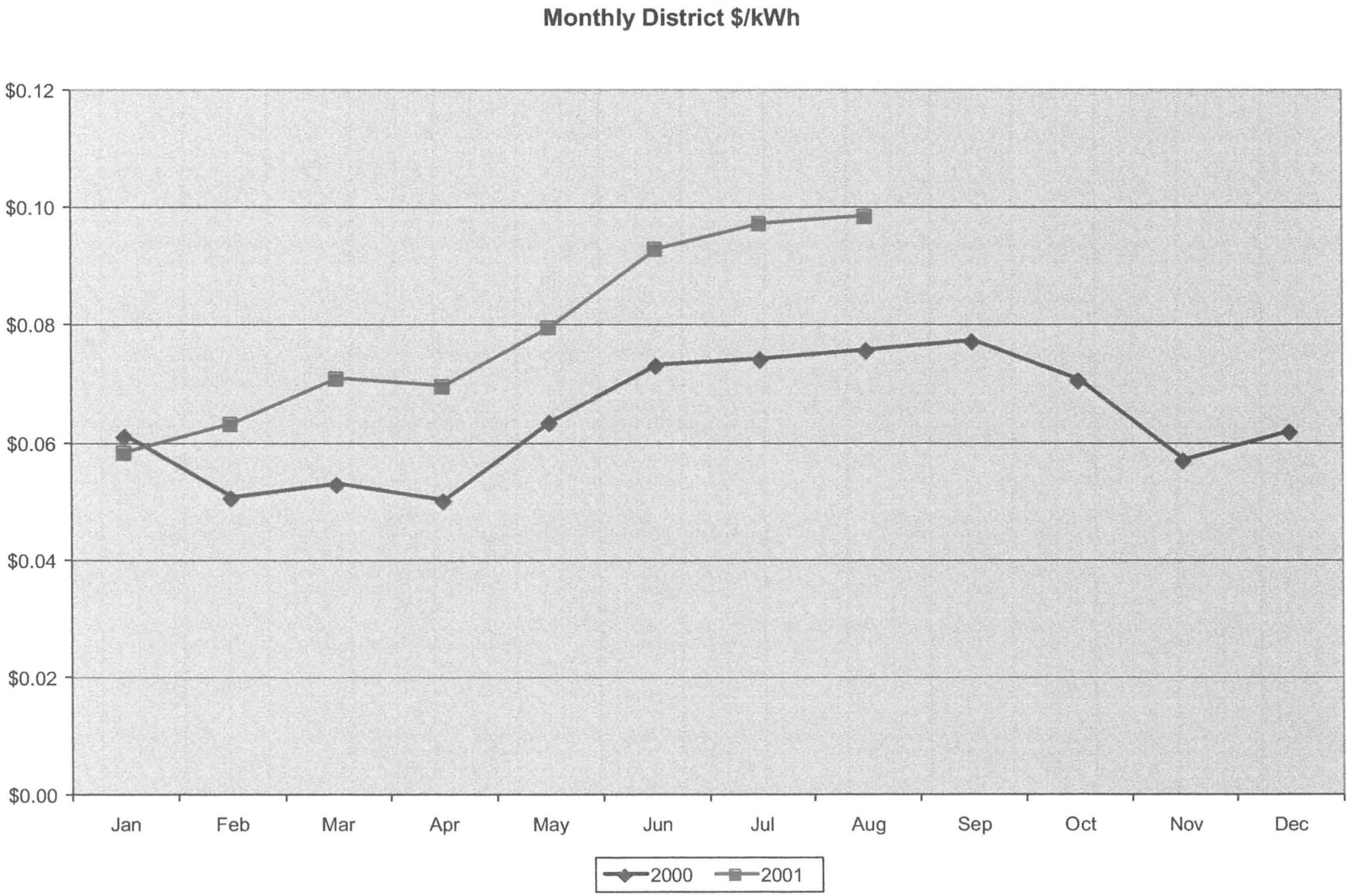
Although historic income is poor, there appears to be potential for as much as $5.5million per year:





Monthly District Energy Cost 2000-2001


Monthly District Energy Usage 2000-2001
2000 Annual = 13,317,476 kWh
kWh
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2000
2001


Monthly District $/kWh
$0.12
$0.10
$0.08
$0.06
$0.04
$0.02
$0.00
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2000
2001

Primary District Energy Usage 2000

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		Jan	Feb	Mar	Apr	May	Jun	Tot 6'00	Jul	Aug	Sep	Oct	Nov	Dec	Tot'00
2	**Coyote Pump Station Acc. BVF N4 10001 (Rate Schedule SPTA10)**														
3	kWH Energy	0	0	0	0		0	0	0	0	120	0	0	0	0
4	$ Cost	75	75	75	75		122	422	122	75	601	75	122	75	1492
5	$ Per KWH Cost														
6															
7	**Vasona Pump Station Acc. SVJ 31 39421 (Rate Schedule A6P)**														
8	kWH Energy	143100	12300	13200	12000	13500	13500	207600	15600	14100	13800	12300	44700	238800	546900
9	$ Cost	11663	915	1097	533	706	1317	16231	1471	1456	1415	1183	4309	18841	44906
10	$ Per KWH Cost	0.08	0.07	0.08	0.04	0.05	0.10	0.08	0.09	0.10	0.10	0.10	0.10	0.08	0.08
11															
12	**Rinconada Water Treatment Plant Acc. BVJ N4 18851 (Rate Schedule SPPA10)**														
13	kWH Energy PG&E	45196	0	6120	38405	105698	141331	336750	177568	194225	161769	155409	102638	101709	1230068
14	kWH Energy West.	328004	412848	426180	532015	539650	540101	2778798	501572	500683	479571	460695	490774	362367	5574460
15	kW Peak Demand	1123	823	989	1010	1099	1159	1159	1178	1195	1118	1114	1006	1054	1195
16	$ Cost PG&E	3598	-107	545	2990	10509	14061	31596	17635	19266	16080	15509	7850	7880	115817
17	$ Cost West.	12343	11794	13500	14228	14076	13706	79647	13106	13896	14224	13491	13251	12771	160386
18	$ Per KWH Cost	0.04	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.04	0.04	0.04
19															
20	**Penitencia Water Treatment Plant Acc. LVP R1 49432 (Rate Schedule E19V)**														
21	kWH Energy	113845	108492	108953	103468	122904	121162	678824	119768	118687	83308	8691	15082	14121	1038481
22	kW Peak Demand	315	342	337	337	295	396	396	286	269	244	163	43	35	396
23	$ Cost	8215	8052	8050	9105	12715	15182	61319	12864	13141	10449	903	1172	1098	100946
24	$ Per KWH Cost	0.07	0.07	0.07	0.09	0.10	0.13	0.09	0.11	0.11	0.13	0.10	0.08	0.08	0.10
25	NEV Savings	429	421	421	477	666	0	2414	0	0	0	0	0	0	2414
26															
27	**Almaden HQ Facilities Acc. SVP T1 48961 (Rate schedule E19P)**														
28	kWH Energy	293361	291522	301746	312780	319992	356137	1875538	357710	330588	332105	320200	280782	273522	3770445
29	kW Peak Demand	768	762	858	900	858	980	980	956	918	932	835	789	706	980
30	$ Cost	19227	19079	19985	20824	27591	37381	144087	37318	35418	35423	32754	22021	18194	325215
31	$ Per KWH Cost	0.07	0.07	0.07	0.07	0.09	0.10	0.08	0.10	0.11	0.11	0.10	0.08	0.07	0.09
32	NEV Savings	1009	1001	1049	1093	1449	0	5601	0	0	0	0	0	0	5601
33															
34	**Santa Teresa Water Treatment Plant Acc. WVP 35 30512 (Rate Schedule E19S)**														
35	kWH Energy	90664	95035	79040	82762	96484	103250	547235	93908	91388	111619	78372	139500	95100	1157122
36	kW Peak Demand	254	241	247	251	250	256	256	249	254	294	294	420	396	420
37	$ Cost	6736	6499	6003	6280	10190	11148	46856	11018	11072	12733	8985	12339	8009	111012
38	$ Per KWH Cost	0.07	0.07	0.08	0.08	0.11	0.11	0.09	0.12	0.12	0.11	0.11	0.09	0.08	0.10
39	NEV Savings	352	339	313	328	534	584	2450	0	0	0	0	0	0	2450
40															
41	Total T6 KWH Energy	1014170	920197	935239	1081430	1198228	1275481	6424745	1264026	1249671	1182292	1035667	1073476	1085619	13317476
42	Total T6 $ Cost	61857	46307	49255	54035	75788	92916	380158	93380	94323	90925	72901	61064	66868	859774
43	Total $ Per KWH Cost	0.06	0.05	0.05	0.05	0.06	0.07	0.06	0.07	0.08	0.08	0.07	0.06	0.06	0.06
44	Total NEV Savings	1790	1761	1783	1898	2649	584	10465	0	0	0	0	0	0	10465

Primary District Energy Usage 2001

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		Jan	Feb	Mar	Apr	May	Jun	**Tot 6'01**	Jul	Aug	Sep	Oct	Nov	Dec	Tot'01
2	**Coyote Pump Station Acc. BVF N4 10001 (Rate Schedule SPTA10)**														
3	kWH Energy							**0**							**0**
4	$ Cost							**0**							**0**
5	$ Per KWH Cost														
6															
7	**Vasona Pump Station Acc. SVJ 31 39421 (Rate Schedule A6P)**														
8	kWH Energy	**15000**	**12900**	**205500**	**174300**	**14700**	**15300**	**437700**	**18300**	**16800**	**15600**				**488400**
9	$ Cost	**1276**	**1172**	**18266**	**15828**	**1486**	**2094**	**40122**	**2788**	**2643**	**2512**				**48065**
10	$ Per KWH Cost	**0.09**	**0.09**	**0.09**	**0.09**	**0.10**	**0.14**	**0.09**	**0.15**	**0.16**	**0.16**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**0.10**
11															
12	**Rinconada Water Treatment Plant Acc. BVJ N4 18851 (Rate Schedule SPPA10)**														
13	kWH Energy PG&E	**0**	**0**	**0**	**103643**	**210311**	**165483**	**479437**	**205599**	**220333**	**176549**				**1081918**
14	kWH Energy West.	**354180**	**294540**	**297708**	**410377**	**450745**	**439329**	**2246879**	**482073**	**472223**	**451243**				**3652418**
15	kW Peak Demand	**809**	**682**	**737**	**1085**	**1207**	**1133**	**1207**	**1174**	**1207**	**1145**				**1207**
16	$ Cost PG&E	**75**	**56**	**75**	**11454**	**23081**	**28709**	**63451**	**35463**	**38042**	**30576**				**167531**
17	$ Cost West.	**12959**	**11102**	**12464**	**15222**	**15857**	**0**	**67604**	**0**	**0**	**0**				**67604**
18	$ Per KWH Cost	**0.04**	**0.04**	**0.04**	**0.05**	**0.06**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**0.05**
19															
20	**Penitencia Water Treatment Plant Acc. LVP R1 49432 (Rate Schedule E19V)**														
21	kWH Energy	**16492**	**16238**	**13500**	**14041**	**13356**	**19364**	**92991**	**24203**	**25552**					**142746**
22	kW Peak Demand	**46**	**47**	**51**	**42**	**38**	**55**	**55**	**57**	**58**					**58**
23	$ Cost	**1387**	**1414**	**1246**	**1497**	**2027**	**3107**	**10678**	**3640**	**4182**					**18500**
24	$ Per KWH Cost	**0.08**	**0.09**	**0.09**	**0.11**	**0.15**	**0.16**	**0.11**	**0.15**	**0.16**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**0.13**
25															
26	**Almaden HQ Facilities Acc. SVP T1 48961 (Rate schedule E19P)**														
27	kWH Energy	**278524**	**245356**	**259255**	**247161**	**281610**	**290182**	**1602088**	**276318**	**272760**					**2151166**
28	kW Peak Demand	**685**	**552**	**727**	**691**	**808**	**825**	**825**	**839**	**813**					**839**
29	$ Cost	**19831**	**18842**	**20198**	**19263**	**28358**	**42590**	**149082**	**45905**	**45225**					**240212**
30	$ Per KWH Cost	**0.07**	**0.08**	**0.08**	**0.08**	**0.10**	**0.15**	**0.09**	**0.17**	**0.17**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**0.11**
31															
32	**Santa Teresa Water Treatment Plant Acc. WVP 35 30512 (Rate Schedule E19S)**														
33	kWH Energy	**98100**	**104100**	**95100**	**100800**	**104400**	**112200**	**614700**	**105900**	**95100**					**815700**
34	kW Peak Demand	**366**	**399**	**405**	**408**	**414**	**420**	**420**	**429**	**429**					**429**
35	$ Cost	**8816**	**9805**	**9154**	**9662**	**14526**	**20066**	**72029**	**20573**	**18371**					**110973**
36	$ Per KWH Cost	**0.09**	**0.09**	**0.10**	**0.10**	**0.14**	**0.18**	**0.12**	**0.19**	**0.19**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**0.14**
37															
38	Total T6 KWH Energy	**762296**	**673134**	**871063**	**1050322**	**1075122**	**1041858**	**5473795**	**1109393**	**1102768**	**643392**	**0**	**0**	**0**	**8332348**
39	Total T6 $ Cost	**44344**	**42392**	**61404**	**72926**	**85335**	**96566**	**402966**	**107675**	**108463**	**33088**	**0**	**0**	**0**	**652886**
40	Total $ Per KWH Cost	**0.06**	**0.06**	**0.07**	**0.07**	**0.08**	**0.09**	**0.07**	**0.10**	**0.10**	**0.05**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**0.08**

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This section documents the current procedure to obtain interconnection (access) to PG&E. Note that the typical procedure is for gas import to the conventional power plant, and electric interconnection to the "grid".

1) **PG&E application forms and interconnection information are provided. This is the only way to interconnect to the grid. A preliminary "transmission study" is recommended. This will lead to a PG&E study**
2) **It is important to understand that, except in the case of "net metering" (see Section 3) the PG&E application process will still have to be initiated. However, in the case of Calero, it is anticipated that a District-owned transmission line be constructed between the new hydro plant and the Santa Teresa site. This would afford the District the ability to "displace" power at current rates in lieu of PG&E interconnection.**

Interconnection Requirements for Sales, and/or Revenue Options

Who	What	Interconnection	Income
PG&E	Standard Offer 1 If PG&E were to "partner" (i.e. in constrained transmission area)	Expensive Paid by PG&E	Well defined, but low Open to negotiation, but poor dispatchability will reduce desirability
State Contract	State DGS and now Power Authority were paying as much as $160/kW/yr for power. All are currently suspended.	Rule 21 and PG&E	Open to negotiation, but poor dispatchability will reduce desirability
APX	This power exchange is still viable	Still through Rule 21 and per PG&E regulations and cost structures	Open to market forces, but poor dispatchability will reduce desirability
Municipal Partners	SVP or CoPA could partner and might be interested in lower capacity plants (i.e. below 6MW)	Still through Rule 21 and per PG&E regulations and cost structures	Open to negotiation, but poor dispatchability will reduce desirability
Merchant Plant Partners	Calpine et. al could partner, but not currently interested in plant size smaller than 50MW	Still through Rule 21 and per PG&E regulations and cost structures	Open to negotiation, but poor dispatchability will reduce desirability
Export to neighbor	Negotiate bi-lateral agreement with adjacent commercial owners.	Complicated and separate wiring may be associated with bi-lateral arrangements.	As much as $0.18 per kwh or more.
Net Metering	Best possible: displacement of current District energy use.	None required, but aggregation and/or "net metering" rules require significant lobbying at State level.	As much as $0.18 per kwh or more.

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For this report, each of the sites was re-visited relative to currently available revenue options as well as potential revenue (or avoided costs). The range of opportunities included:

1) **The current contract at Anderson involves PG&E's Standard Offer #1 (SO-1). Revenues from this contract are based on "short term average cost" and are generally very low (on the order of $0.03/kwh). HOWEVER, as may be noted from the curves of actual CFS vs. produced power (kWh), there is potential for between $29,000 and $68,000 in unrealized real income using the existing plant.**
2) **The "high income potential" scenario involves exporting power to an adjacent commercial property and/or displacing power (avoiding PG&E power purchases) through a "net metering" scenario. Although these opportunities provide theoretical "income" of as great as $0.18 per kWh, the "suspended" market is not currently supportive.**
3) **The power can be sold to APX[2], which includes a premium for "green power". However, this option is generally not practical under 1MW, so the District may need to combine forces with other small generators or implement additional generation capacity to overcome the market fees. Likewise, interconnection to the grid and a robust, deregulated marketplace is required in order to sell power through the APX.**

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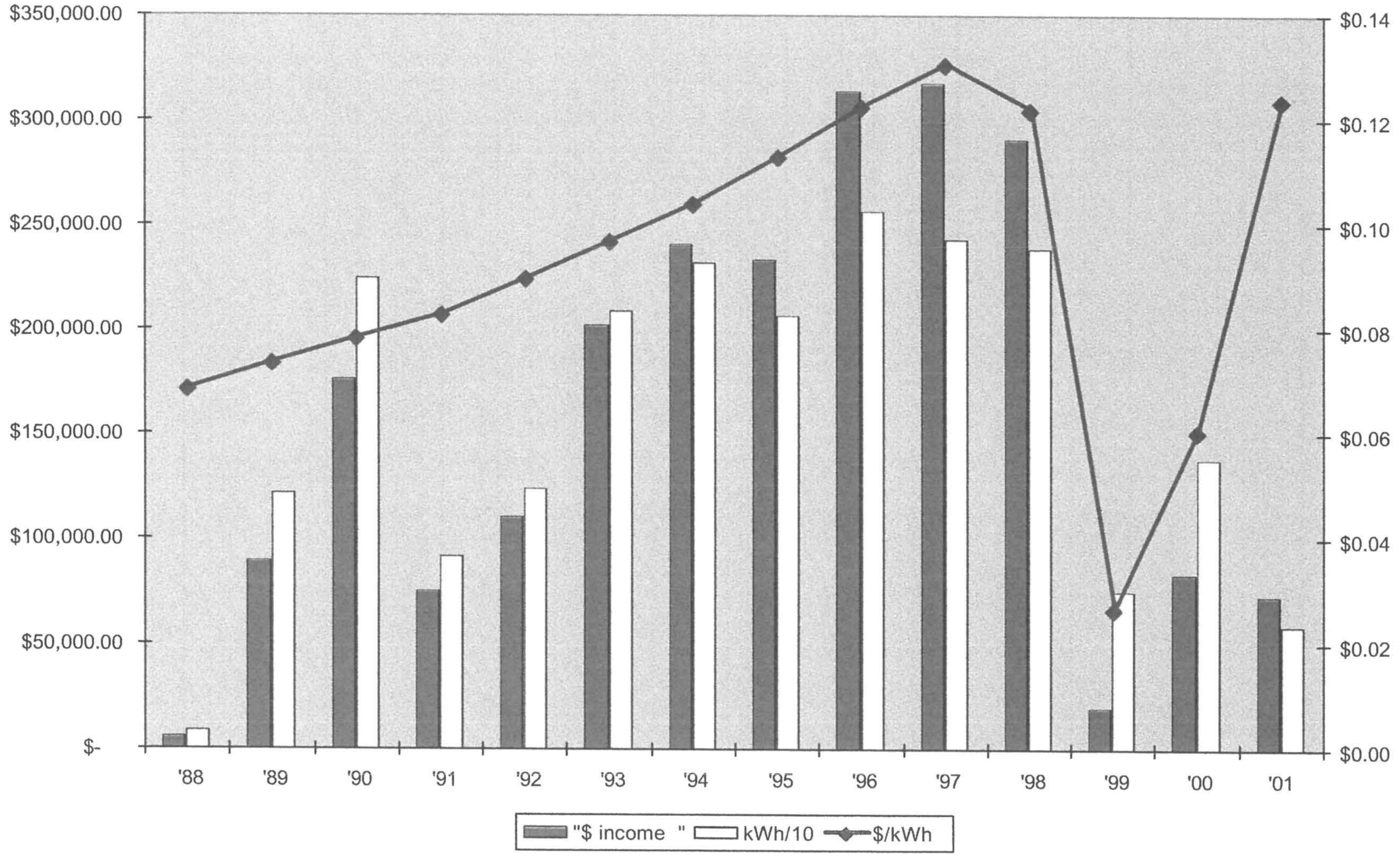
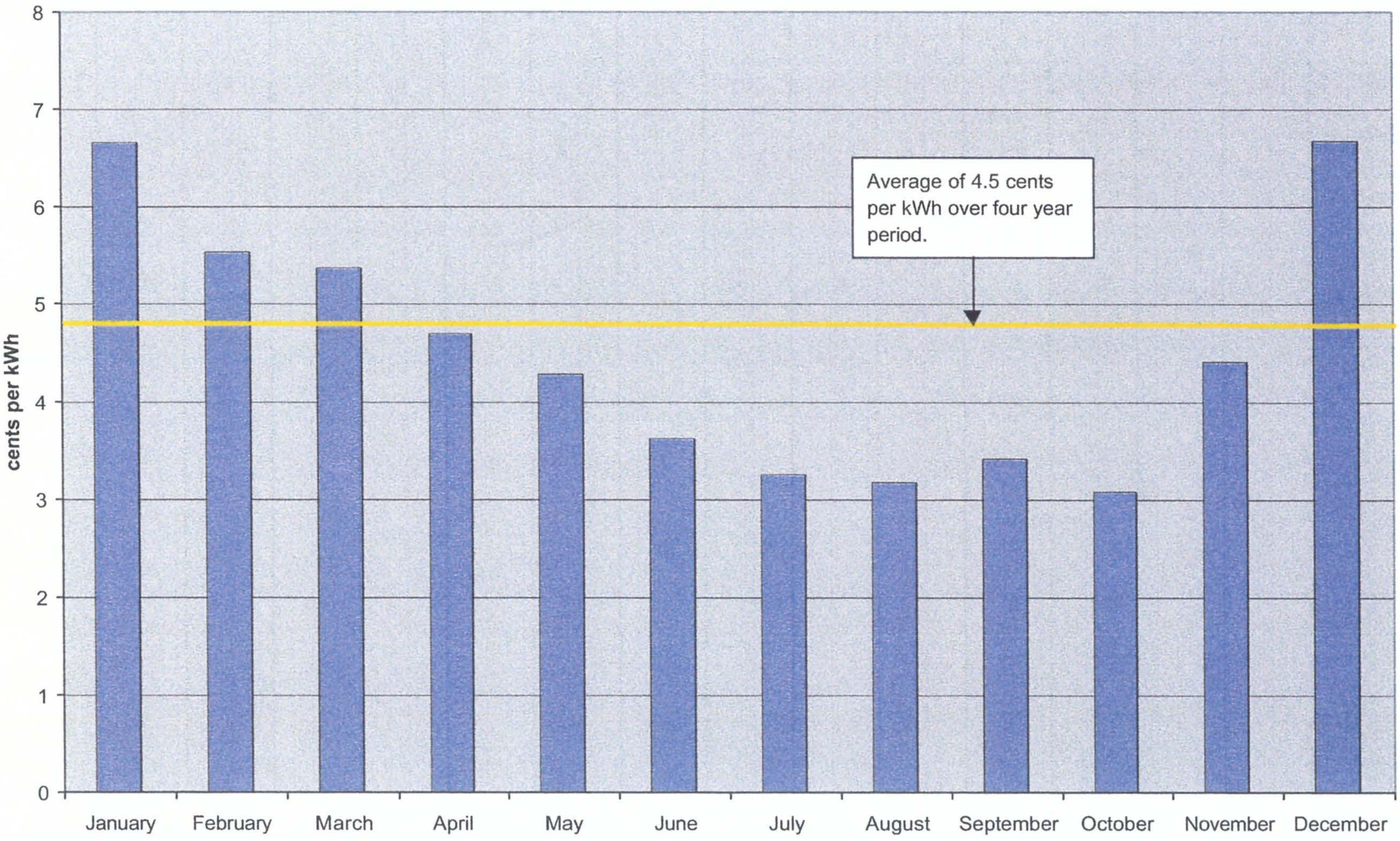
[2] Automated Power Exchange

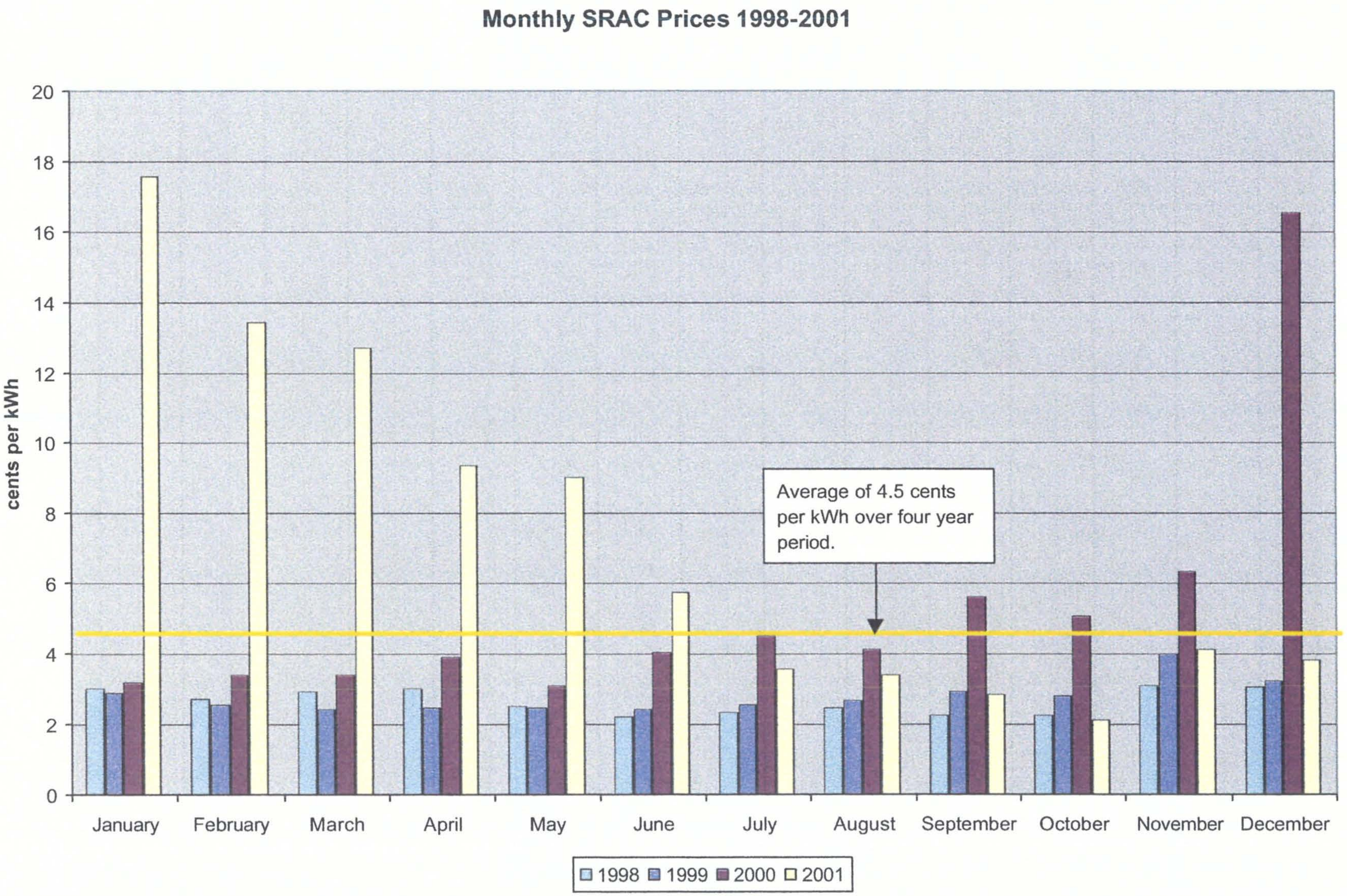
Anderson Annual Income & Energy vs. $/kWh



Average Monthly SRAC Price 1998-2001

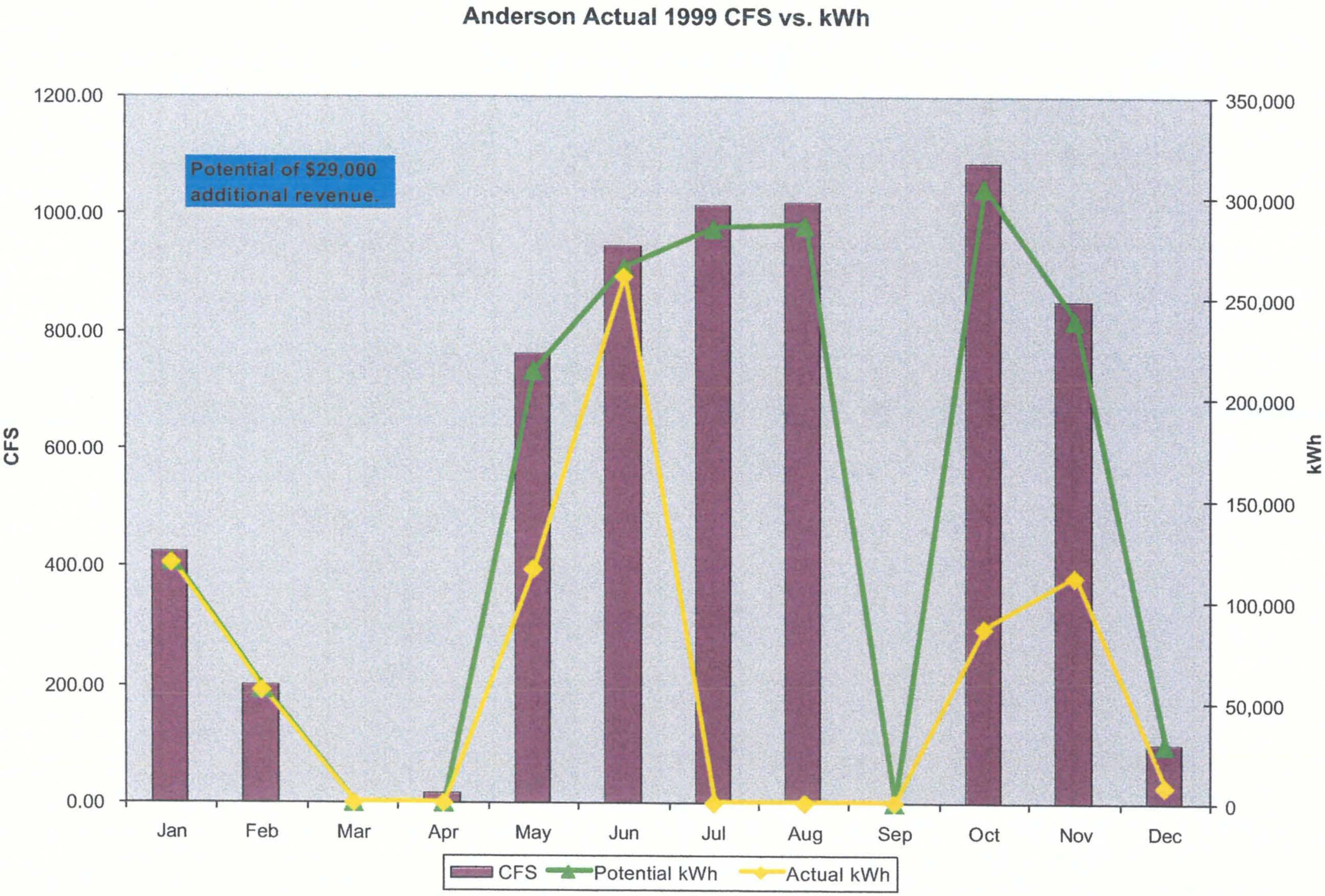


Average of 4.5 cents per kWh over four year period.

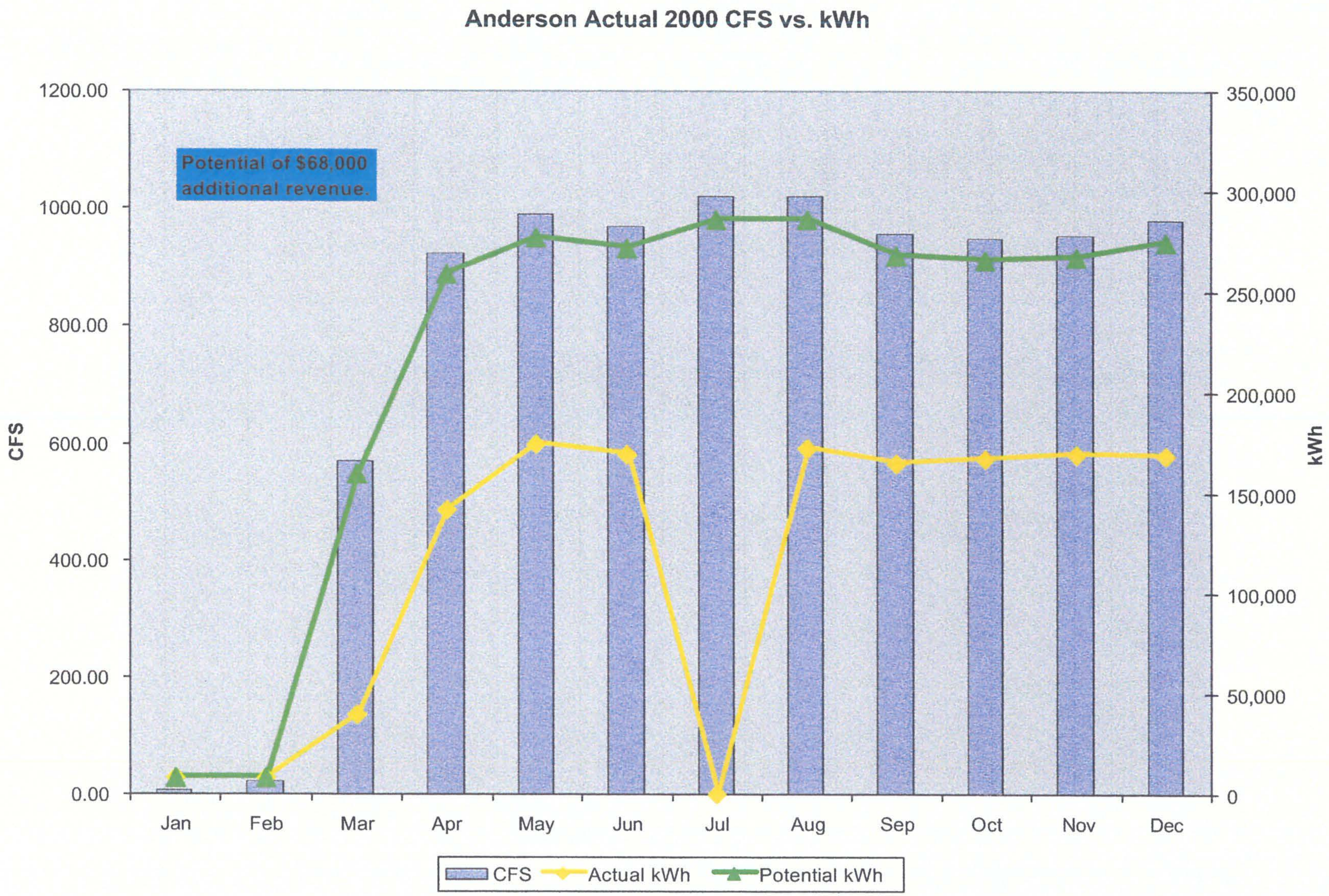


Average of 4.5 cents per kWh over four year period.

1999 Anderson Potential



2000 Anderson Potential



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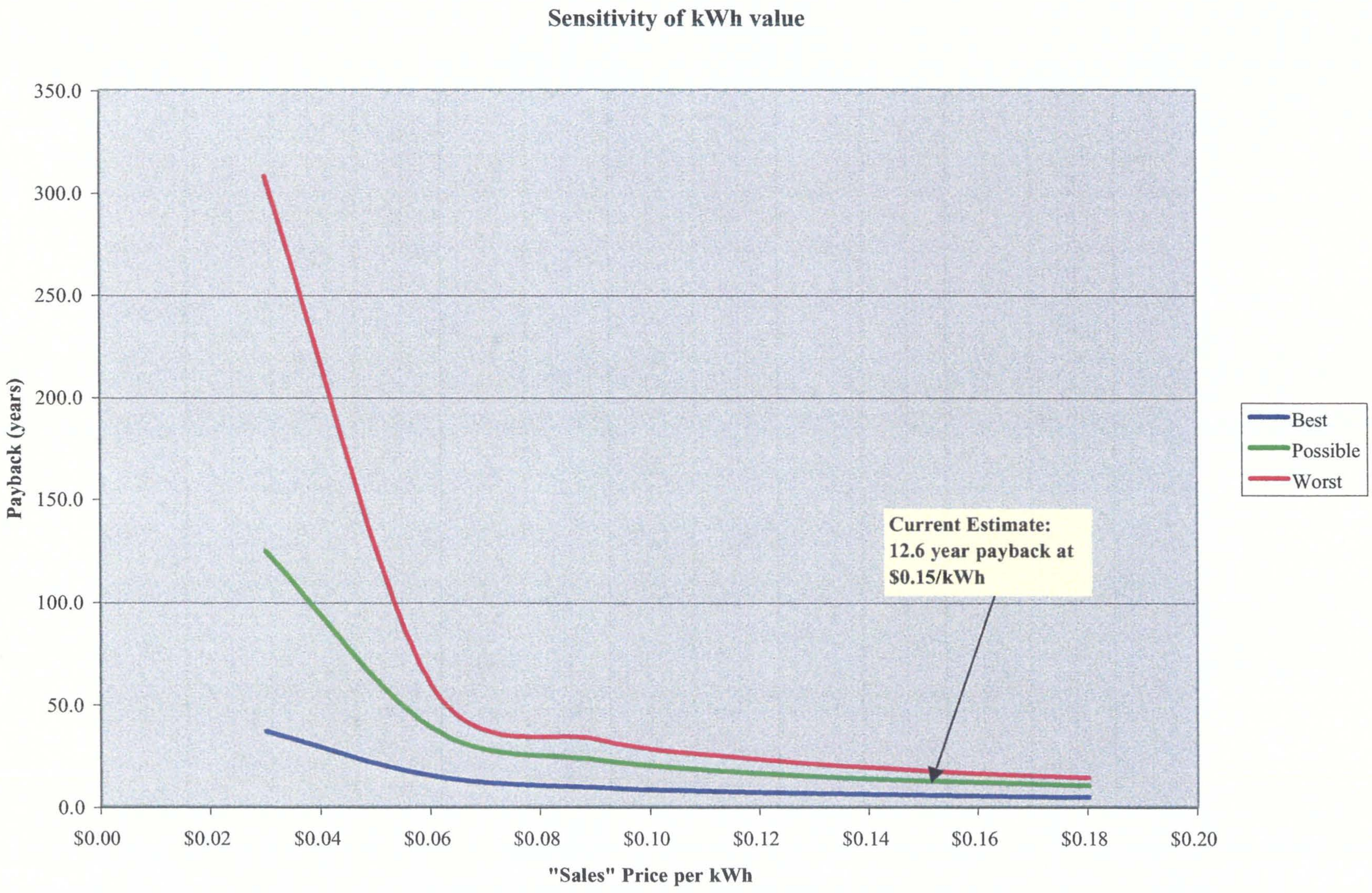
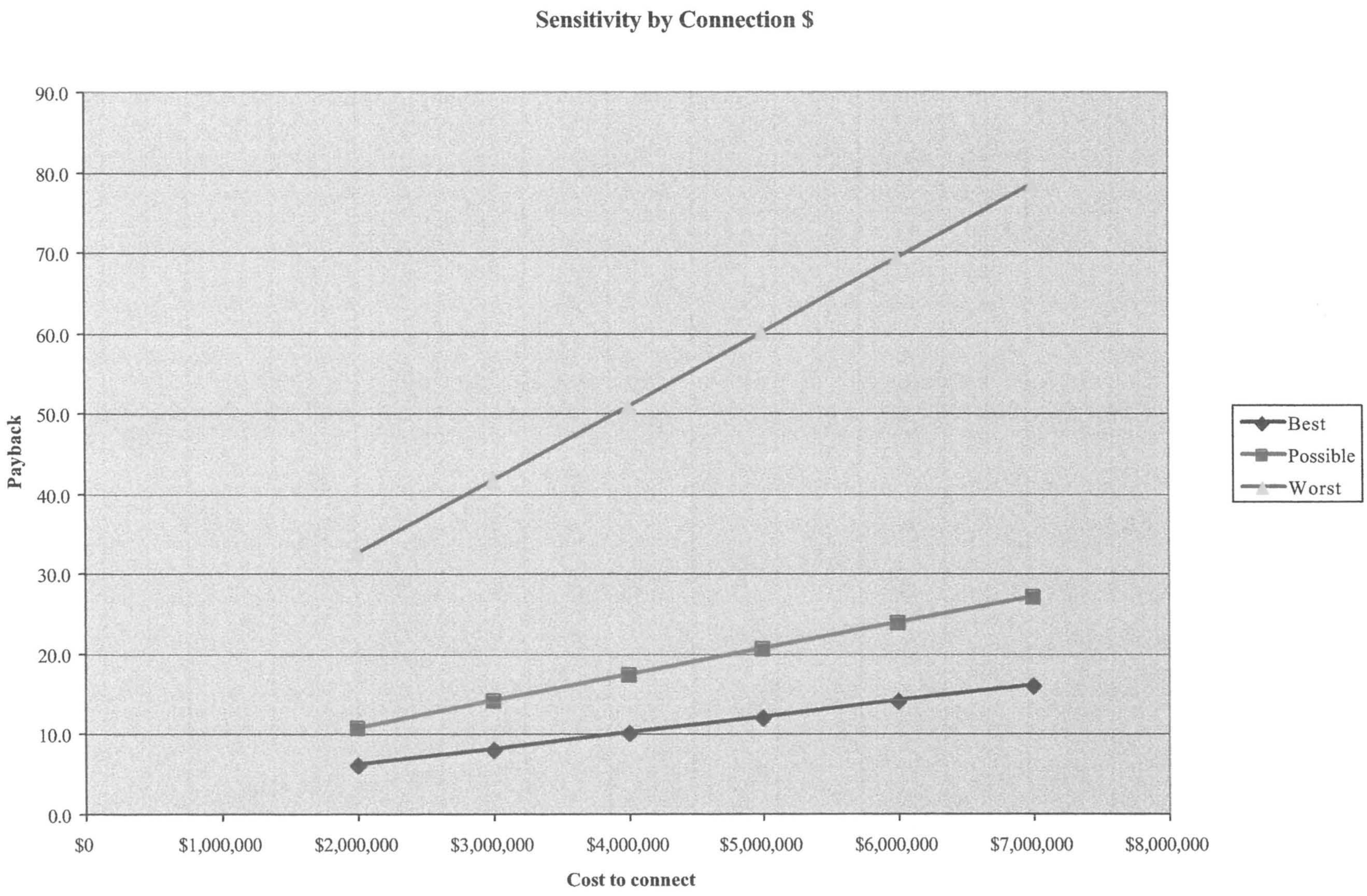
FOR FUNDING CALERO THROUGH NORMAL DISRICT MECHANISMS:

- **Because of the sensitivity to many variables a parametric study was developed for the Calero site in order to provide a "payback" or return on investment associated with the recommendation in the Executive Summary. As may be noted, paybacks between 5 and 10 years appear to be realistic in both "best" and "possible" scenarios (as indicated on the curves which follow).**

POSSIBLE FUNDING ENHANCMENTS TO OTHER (FUTURE) SITES:

- **The California Power Authority currently needs legislative approval to invest in hydro projects (see attached communications from the CPA). The District should monitor this option closely, as "pipeline hydroelectric" projects represent a large potential for the state. Likewise, it is supposed that the legislature required this because the CPA was only considering hydro projects being built from scratch (i.e. new dams rather than capturing excess energy on an existing pipeline). The District may wish to join forces with other water districts to lobby for an amendment.**
- **Most CEC incentives currently do not include hydroelectric generation. Pipeline hydro was not considered. Given that existing CEC incentives for renewables such as solar and wind pay up to $4,500/kW and the full cost of hydro plants is in the $2,500/kW range, the CEC should consider these "hidden" and inexpensive renewable energy sources. Again, the District may wish to join forces with other water districts to lobby for incentives in this area. See the attached pie chart of the effect of State & Federal incentives on the cost of other renewable sources.**


Sensitivity of kWh value
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Payback (years)
$0.00
$0.02
$0.04
$0.06
$0.08
$0.10
$0.12
$0.14
$0.16
$0.18
$0.20
"Sales" Price per kWh
Best
Possible
Worst
Current Estimate:
12.6 year payback at
$0.15/kWh


Sensitivity by Connection $
Payback
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
$0
$1,000,000
$2,000,000
$3,000,000
$4,000,000
$5,000,000
$6,000,000
$7,000,000
$8,000,000
Cost to connect
Best
Possible
Worst

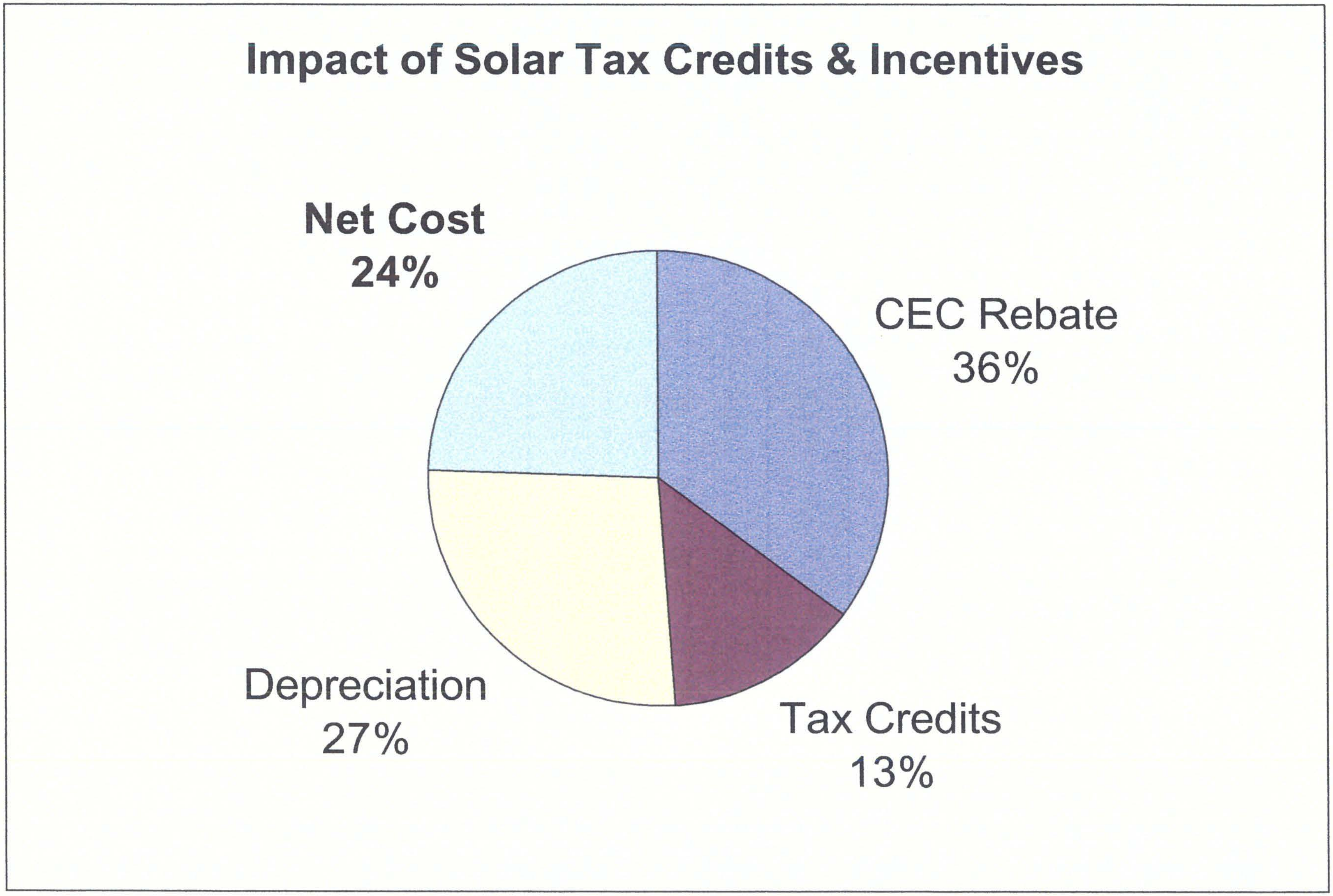
Calero

			Greenhouse Emissions Reductions	
Criteria			CO2	SOx
Capacity	550	kW	11,720,000	111,340
Probable Generation	2,930,000	kWh		
Efficiency	65%			
Incentives	$137,500	@$250/kW		
Connection Distance	19,800	feet		
Connection Cost	$4,950,000	@ $250/ft		
Other costs	$0			
Maintenance Cost	$14,650	@ 0.005/kWh		
Other Recurring costs	$12,500	$50,000 every 4 years		
Total recurring costs				

Outcome:	Best	Possible	Worst	This Recommendation
Installed Cost	$2,227,500	$4,950,000	$6,490,000	$3,251,875
Net Annual Income	$412,350	$391,450	$372,700	$412,350
Payback	5.4	12.6	17.4	7.9
Variables:				
Cost/kW	$2,200	$2,500	$2,800	$2,200
kWh per year	2,930,000	2,930,000	2,930,000	2,930,000
Displaced $/kWh	$0.15	$0.15	$0.15	$0.15
Connection cost	$1,237,500	$3,712,500	$4,950,000	$2,041,875
Annual Maintenance Cost:	$14,650	$29,300	$29,300	$14,650
Other Recurring Costs:	$12,500	$18,750	$37,500	$12,500
Incentives:	$220,000	$137,500	$0	$0

Best, Possible, Worst	$/kwh	Best	Possible	Worst
sensitivity	$0.18	4.5	10.3	14.1
by $/kwh	$0.15	5.4	12.6	17.4
	$0.12	6.9	16.3	22.8
	$0.09	9.4	23.00	33
	$0.06	15.0	38.7	59.5
	$0.03	36.7	124.2	307.6
	Capital Cost:	*$2,227,500*	*$4,950,000*	*$6,490,000*

Best, Possible, Worst	Connect	Best	Possible	Worst
sensitivity	$7,000,000	16.0	27.1	78.3
by connection cost	$6,000,000	14.0	23.8	69.2
$/kwh range .06 -.12	$5,000,000	12.0	20.5	60
	$4,000,000	10.0	17.3	50.8
	$3,000,000	8.0	14	41.7
	$2,000,000	6.0	10.7	32.5


Impact of Solar Tax Credits & Incentives
Net Cost 24%
CEC Rebate 36%
Tax Credits 13%
Depreciation 27%

From:	Flynn, Thomas [Thomas.Flynn@dgs.ca.gov]
Sent:	Tuesday, December 18, 2001 1:46 PM
To:	'chris@salasobrien.com'
Subject:	hydro project

Chris,

I received your inquiry regarding CPA interest in "one or more hydro plants to capture excess energy on an existing pipeline." By definition this is a "hydro" project requiring specific approval by the legislature. That is, our statute specifically states that the CPA may not invest in or develop additional hydroelectric facilities without first receiving specific statutory authorization to do so on a project-by-project basis.

Tom Flynn
Assistant Director, Renewables
CA Power Authority
916-651-9750

From: Flynn, Thomas [Thomas.Flynn@dgs.ca.gov]
Sent: Tuesday, December 18, 2001 2:08 PM
To: 'Chris Beekhuis'
Subject: RE: hydro project

I've had other such inquiries as yours (i.e., entities which are interested in developing a hydro project). I've told them all that it's up to them to lobby the Legislature for such changes. To my knowledge the CPA is not actively appealing to the Legislature for such changes. I do not have a sense of how worthwhile an effort it would be. Hope that helps.

Tom Flynn

-----Original Message-----
From: Chris Beekhuis [mailto:chris@salasobrien.com]
Sent: Tuesday, December 18, 2001 1:58 PM
To: Flynn, Thomas
Subject: RE: hydro project

Tom,

Thank you for the information on the CPA's statute restriction on investment in hydro projects. Are you aware of a legislator or legislative contact I could speak with about an amendment that would exempt non-dam hydro projects? Do you have a sense or opinion of whether that would be a worthwhile effort?

Thank you,

Chris Beekhuis

-----Original Message-----
From: Flynn, Thomas [mailto:Thomas.Flynn@dgs.ca.gov]
Sent: Tuesday, December 18, 2001 1:46 PM
To: 'chris@salasobrien.com'
Subject: hydro project

Chris,

I received your inquiry regarding CPA interest in "one or more hydro plants to capture
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Tom Flynn
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CA Power Authority
916-651-9750

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Major Section Elements:

In the robust year of California's deregulation experiment a number of public and private partnerships were available.

These included:

The State:	**California Power Authority**
Utility:	**PG&E, Duke, et. al.**
Muni:	**Silicon Valley Power, City of Palo Alto**
Merchant:	**Calpine, Chevron, et. al.**

Due to the "suspended" condition of California's restructuring effort, only the PG&E option is currently available.

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STATE OF CALIFORNIA

CONSUMER POWER AND CONSERVATION FINANCING AUTHORITY

Welcome

Please note the change to the Energy Resource Investment Plan Meeting scheduled for **Friday, February 8th, 2002** in Sacramento. The meeting location has been changed to:

Energy Commission Conference Room
1516 9th Street

Public Comment to begin at 10 am

○ My CA ○

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CONSUMER POWER AND CONSERVATION FINANCING AUTHORITY

Background

The California POWER Authority
Powering California with Reliable, Reasonable and Green Energy

The California Consumer Power and Conservation Financing Authority (Authority) is charged with the responsibili
sufficient surplus of electricity so that Californians **never again** face electricity shortages or outrageous prices.

Electricity is a precious and unique commodity. It is essential to our economic health just as water is essential to
health and safety. As California nearly witnessed in 2000 and 2001, an electricity shortage could prove disastrou
up prices resulting in potential economic harm to residential consumers and businesses alike. Because of its uniq
essential nature, it is necessary to supplement private enterprise efforts to assure adequate electricity supply at
prices. The Authority is charged with the responsibility of ensuring reliable electricity, at reasonable prices. By div
electricity portfolio to include increased renewable energy, permanent conservation efforts, and cleaner burning
the Authority can prepare California to respond to any eventuality.

Critical to California's long-term success is the understanding that electricity reserves, like insurance or spare par
economic imperative. As California prepares for earthquakes, droughts, or more motorists on its freeways, so to
prepare for the likelihood of an electricity shortage. Californians should not be lulled into a false sense of securit
respect to the acquisition of additional electric supply. Take this year for example. Peak energy load was conside
than projected, conservation was significantly higher than anticipated, and the weather was mild. New power pla
completed on schedule, old plants did not break down as anticipated and state agencies, businesses and the pu
well together. Despite these positive factors, blackouts remained a distinct possibility. Most importantly, these po
factors cannot be counted upon in the future.

There are seven main reasons for California continue with its acquisition of additional resources to ensure suffici
available to meet consumers' needs. They are:

RESERVES MUST BE RESTORED TO SAFE LEVELS. Reserves are a critical component of any electrical syste
can and will break down when needed most. Unlike the airline that cancels a flight for mechanical failures, the li
always stay on. Historically, utilities have always had 15% more capacity, either in units that they owned or purc
contracts, than high peak loads. This covered the operating reserve as well as reserves for units broken or out o
any reason.

The 15% reserve has disappeared as deregulation has progressed, since no private generator holds a 15% over-
that is seldom used. It is more critical than ever for the state to restore these reserves because of the age of the
fleet in California. Sixty percent of our generation fleet is over 30 years old, and much is over 40 years old. It is
end of its expected life, and will be retiring from service voluntarily or involuntarily with increasing frequency ove
several years.

An analogy could be made here to the national strategic petroleum reserve. Customers everywhere finance and
seldom-used oil reserves because of the critical nature of this commodity and the need to ensure sufficiency of s
there is a shortage. This reserve is used to provide protection from price gouging and to ensure continuity of su
power capacity reserves will be used.

produce 30-40% more electricity on the same amount of natural gas input than the old design while emitting les than a plant with an emission control retrofit.

CALIFORNIA MUST ACHIEVE A DIVERSE POWER PORTFOLIO THAT INCLUDES RENEWABLE RESOUI California, through the Authority, has the opportunity to significantly diversify its power portfolio with additional r -- upwards of 1,000 MW -- using green sources that include wind, solar, and other alternative renewable technol While demonstrating California's commitment to improve air quality, the Authority can help ensure continued uni supply of low-cost electricity and hedge against the potential for spiking natural gas prices. Additionally, a signific commitment on the part of the Authority will provide encouragement for additional investment in research and manufacturing of renewable technologies and equipment. Over the next 5 years California will need to add apprc 3,000 MW of clean power to meet the Governor's target of 17% of its supply being renewable.

PEAK LOAD NEEDS MUST BE MET AT REASONABLE PRICES. The responsibility of the Authority is to ensu reserves so that Californians **never again** face short supplies or outrageous prices. The Authority will take actio the 15% reserves that have historically been available. While it may be appropriate to rely to some extent on the market to provide a portion of peak load needs, in order to assure reliability and price mitigation, the Authority s determine an appropriate peak load level to place under its control.

Without government owned peakers, at superpeak time, the last megawatts will only be available at super premi if at all. A shortage of this nature drives all prices up in the short-term markets. Having a substantial portfolio un Authority's control will assure California of a steady stream of uninterrupted power at cost-of-service rates. A por combines 1,000 MW of renewable energy with perhaps 2,000 MW of peaking units and load management which Authority can dispatch at a moments notice will provide the state with the best opportunity to meet capacity nee as summer 2002.

In addition to managing peak loads, peak resources have another tremendous benefit. Since renewable energies intermittent resources, which means they only produce power when the wind blows or the sun shines, somethin done to "firm up" that power so that it is dependable. Peaker units fill this function perfectly. They can start in m come off-line just as quickly.

COSTS OF OPERATING RESERVES CAN BE DRASTICALLY REDUCED. Operating reserve and regulation, t "ancillary service," consist of generating units on-line which are not fully loaded, but are prepared to load up to r sudden changes of load or loss of other generating units. The State of California spends $600 million on these se annually. Reserves at peak times tend to be between 2,500 and 3,200 MW. If the Authority owned several thous megawatts of resources that could be used for reserves, then these services could be had for half the current co of costing us whatever the market will bear.

EMERGENCY RESPONSE AND ELECTRICAL SYSTEM RELIABILITY CAN BE IMPROVED. Emergencies, s loss of many generating units or significant transmission lines are a regular fact of life in an electrical system. Th happen at the worst possible time when weather is hot, loads are high, and equipment is stressed to its maximu economic consequences of significant blackouts are far too high to take significant risks. An array of quick start by the Authority would serve California well in its ability to mitigate emergencies and quickly restore power when emergency strikes.

In summary, the Authority stands poised to do important work to preserve and improve electricity reliability, enh environmental quality and lower the cost of an essential commodity for California businesses and consumers.

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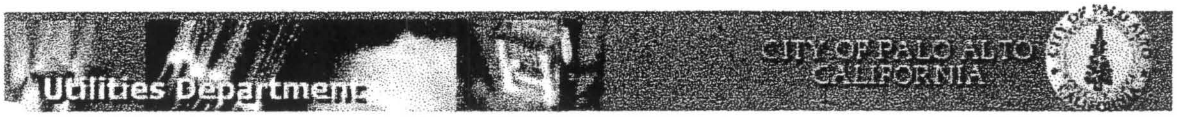

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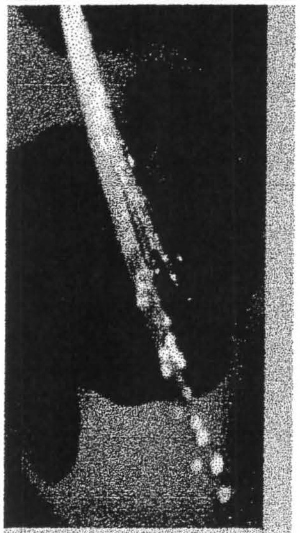

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- Facts about your utilities.

Energy Forum No.3 Questions & Answers

UTILITIES DEPARTMENT

Mission Statement: "To build value for our citizen owners, to provide dependable returns to the City and citizens of Palo Alto, and to be the preferred full service utility provider while sustaining the environment.."

CITY OF PALO ALTO
UTILITIES

The City of Palo Alto Utilities (CPAU) is the only municipal utility in California that operates city-owned utility services that include electric, gas, water, and wastewater collection services.

NEWS

US Secretary of Energy, Spencer Abraham, conducted a brief news conference on October 18 in the City Hall Council Chambers. Click here for our follow-up news release.

EFFICIENCY PROGRAMS

Photovoltaic (PV) Partners Rebate Program: **NOTE: PV Partners program will change with new rebate limits as of January 1, 2002! PV Partners offers eligible Palo Alto residents and businesses a rebate up to $4.00 per watt for installing and generating electricity from a photovoltaic (PV) system.** Click here to sign up. For more information email us or call (650) 329-2241.

Commercial Advantage Program: Get rebates for the purchase and installation of qualifying energy efficiency improvements in local businesses. Click here to sign up now. If you need additional information on this program, email us!

Residential Appliance Rebate Program: For rebates on new energy efficient appliances, click here! If you need additional information on this program, click here or email us.

SIGN UP NOW! for our Renewable Energy Program: Palo Altans can choose how much of their electric bill will go towards supporting renewable energy resources such as solar, wind and hydro power! If you would like to sign up for the **Future Green** program, mail us. For more information about how CPAU customers can help the environment, call the Future Green Information Line at (650) 329-2443.

Since January 2001, the Palo Alto community has reduced it overall electricity use by about 15%, helping us to avoid rolling blackouts here since March. At this time, the California ISO continues to issue intermittent Warning Alerts but there are no expectations for rolling blackouts at this time. **Please continue your critical conservation efforts to help avert possible rolling blackouts!**

SIGN UP NOW for the automatic email notification of ISO Electricity Alerts, through the State's Special ISO Emergency Alert and Warning Bulletin Service and visit the Independent System Operator's (ISO's) System Conditions and Power Watch 2000 pages for current conditions.

There are no exemptions from rotating outages in Palo Alto, except for hospitals and the City's Emergency Operations Center. In the event of a rolling blackout, you will be without power for one hour. Click here for savings tips. Click here for other information resources. Since rotating outage blocks do not have clear geographical descriptions, click here to determine **your CPAU customer rotating outage block number.**

Monthly Weather Data

December 2001	55 degrees Fahrenheit	65 degrees Fahrenheit
Heating Degree Days	143	444
Cooling Degree Days	9	0

Of General Interest:

- Customer-furnished Meter Readings form

Utilities Advisory Commission:

- Utilities Advisory Commission Agenda

Standing Oversight Commission:

- Standing Oversight Commission Agenda & Minutes

Electric Service Information:

- Electric Service Requirements
- Electric Load Sheet

Water, Gas and Wastewater Service Information:

- Water-Gas-Wastewater Service Application Procedure
- Application Form for NEW Service
- Water-Gas-Wastewater Load Sheet

Fiber Optic Services Information:

- Dark Fiber Services
- Fiber to the Home (FTTH) Trial Information
- Universal Telecommunications System (UTS)

August 2, 2001
Energy Forum No.3 Questions and Answers

Q. Has the new COBUG arrived to replace the diesel COBUG? In September, the natural gas back up generator will be in operation.

Q. How much energy is used by what sector? 85% Large Commercial and 15% Residential.

Q. Has the Utility made a profit on its energy sales? CPAU had a $45,000,000 financial gain in the last fiscal year. This will help make up for the projected loss in revenue in the next 3.5 years of $44,000,000. Other good news for local consumers is that Palo Alto electric rates should stabilize after the 43% rate increase in July, and our rates remain 20-40% below PG&E's. Natural gas rates are expected to come down in the next fiscal year.

Q. Has the City of Palo Alto considered PG&E's $200 rebate program for refrigerators? The PG&E program ran out in July. However, CPAU has an ongoing appliance rebate program for $125 per refrigerator.

Q. With the recent 43% electric rate increase this July, will the same increase apply to the green power option? No. Green Power participants will pay the same premium as in the past.

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Pacific Gas and Electric Company

WE DELIVER ENERGY.

PAY MY BILL | NEW SERVICE | CLOSE SERVICE | TRANSFER SERVICE | REVIEW ACCOUNT | MAKE APPOINTME

Search ☐ GO

Energy is in short supply in California. Be Safe. Prepare yourself with tips and guidelines. **Power Outage Safety**

- Residential Services
- Business Services
- Save Energy & Money
- Safety Information
- Career Opportunities
- News & Information
- Our Community
- Rates & Regulation
- About Us
  - Company Profile
  - Career Opportunities
  - Community
  - Purchasing Program
  - Education & Training
  - Facilities for Rent
- Contact Us

Company Profile

Pacific Gas and Electric Company
Serving customers from Eureka to Bakersfield.

Officers
Officers of Pacific Gas and Electric Company.

PG&E Corporation
PG&E Corporation is an energy-based holding company.

About the Site
Please read our disclaimer and Internet Disclosure Policy.

Stock Price
Latest stock quote for PCG-NYSE.

Annual Report
PG&E Corporation annual reports shareholders.

Environmental Leadership
We're committed to being an env leader.

PG&E: "Our History"
A compact history of the rough-ar pioneer gas and electric compani ultimately to form Pacific Gas anc Company.

Home | Site Index | Feedback/Questions | Disclosure
Pacific Gas and Electric Company is a subsidiary of PG&E Corporation

PG&E Corporation

home officers news financial info employment

National Energy Group

National Energy Group

With regional offices from coast to coast, PG&E Corporation's National Energy Group is one of the nation's leading competitive power producers, has natural gas facilities that connect major producing regions to some of the fastest-growing markets in North America, and operates one of the top energy trading businesses in the country.

- 30 power plants in 10 states
- More than 10,000 megawatts in new power plant development and construction
- Generation portfolio of 7,000 megawatts
- Ability to transport 2.7 billion cubic feet of natural gas a day from cost-competitive, abundant supplies in Western Canada
- Interconnects to 6 natural gas pipelines
- Trading volume in 2000:
  - 283 million megawatt-hours of power
  - 6.5 billion cubic feet per day of natural gas

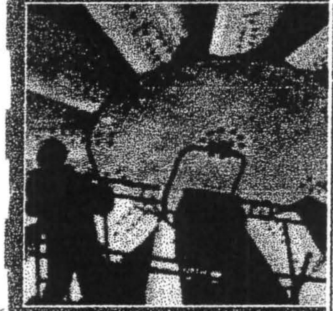
PG&E National Energy Group

The PG&E National Energy Group is not the same company as Pacific Gas and Electric Company, the utility, and is not regulated by the California Public Utilities Commission. Customers of Pacific Gas and Electric Company do not have to buy products or services from the National Energy Group in order to continue to receive quality regulated services from Pacific Gas and Electric Company.

ABOUT US INVESTOR RELATIONS ENERGY ASSETS

CALPINE℠

Energy Assets . . .



Energy Centers . . .

Business Units . . .

Our Technologies . . .

Energy Solutions

Electricity To Your Home . . .

Energy Solutions:

Energy Solutions for California

California is experiencing an energy crisis. Throughout the state, demand for electricity is outstripping supply. In ten years, California's demand for electricity increased by approximately 10,000 megawatts, while only 1,000 megawatts of new generation were added. The state's aging and polluting power facilities are becoming increasingly unreliable and cannot adequately meet today's economic and environmental standards. Further, energy imports from other states are very costly and are not always available to meet California's energy needs.

Energy shortages have already caused power interruptions for California families and businesses and resulted in soaring energy bills in some areas.

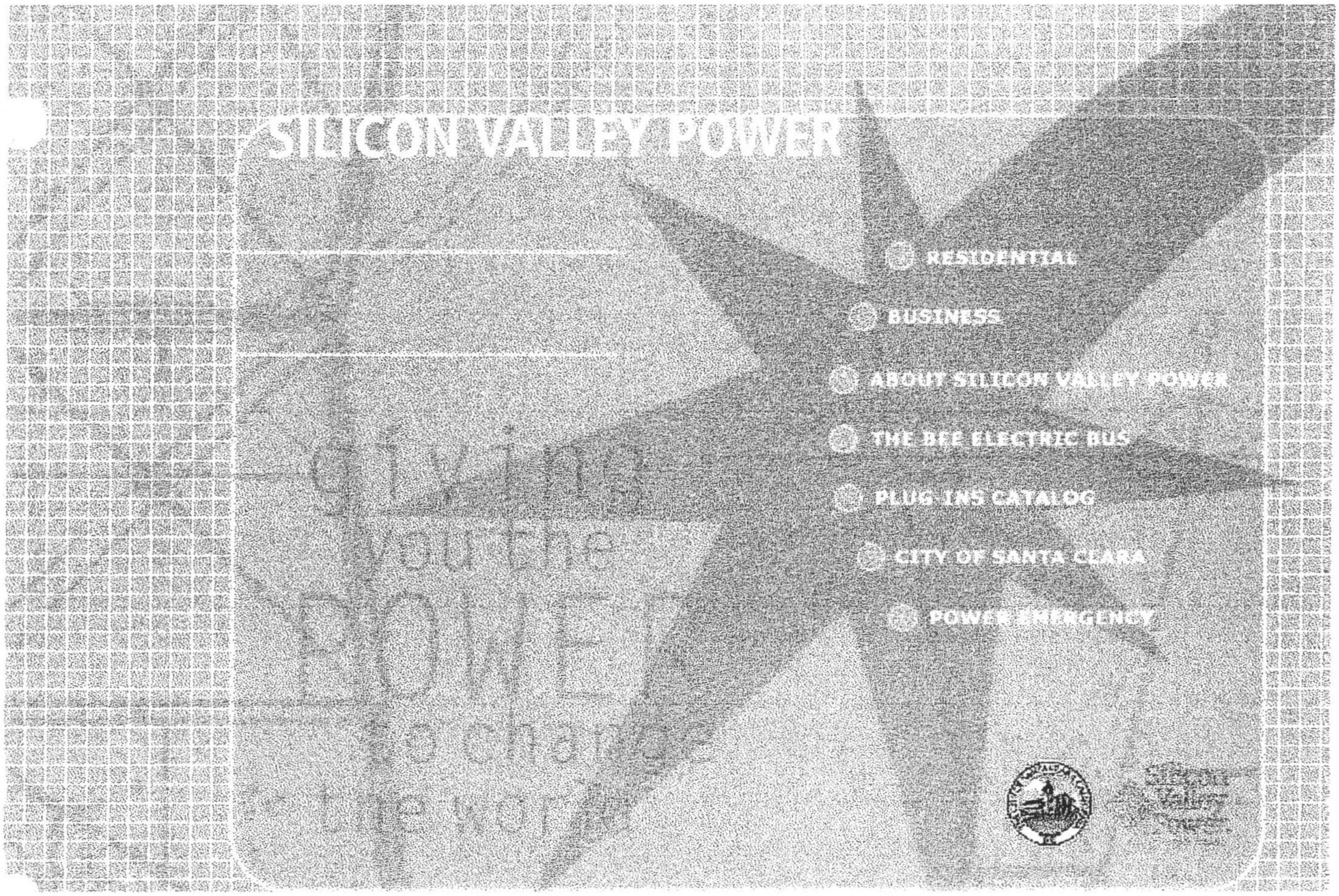
San Jose-based Calpine Corporation is working with state officials to help solve this problem. The company has undertaken a $4 billion building program -- the largest in the state -- to build new generating facilities in California and to ensure California continues to enjoy clean and reliable energy to sustain our economy and quality of life. In addition, Calpine was the first to enter long-term contracts with the California Department of Water Resources to provide the state with much needed electricity.

This summer, Calpine will bring on-line California's only major new power generation facilities -- Sutter and Los Medanos Energy Centers. Together, these facilities will produce more than 1,000 megawatts of electricity for Northern California households.

By 2005, Calpine will generate in excess of 8,000 megawatts of electricity in California. Millions of homes and businesses will use clean, reliable electricity generated by Calpine.

Energy Saving Tips:

Don't overheat your home
Increasing the thermostat
degree can increase your
as much as 3 percent.
Turn off your appliances
aren't using them --- part
your computer.
Keep curtains closed. This
heat loss in the winter an
gain inside your home in
summer.
While compact fluorescen
cost more than conventio
incandescent bulbs, they
energy and last longer. A
plus for homeowners with
ceilings -- you don't have
them as often.
Window coverings, partic
heavy, lined curtains, help
drafts. Even vinyl shades
mini-blinds will help keep
air if they fit properly.
When shopping for new a
or electronic equipment,
Energy Star® products th
less power and cut carbon
emissions.
Wash only full loads when
your clothes washer and d
don't forget to clean your
trap after each use.
Caulk around windows an
weatherstrip around doors
Fix defective plumbing an
faucets, which can waste



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A. Executive Summary
B. Report
  1. Physical Feasibility
  2. Coincident Energy Demand
  3. Transmission Options and Fatal Flaws
  4. Revenue Options and Fatal Flaws
  5. Incentives and Funding Options
  6. Partnership Options
  7. **Potential Legal and Regulatory Flaws**
C. Appendix

Major Section Elements:

- **The experience of Anderson has taught the district that the FERC dam safety reporting requirements can be costly. However, non-dam sites such as Calero and Kirk/Page may not have the same level of requirements and could be more efficient to manage.**
- **Although alternatives for selling the power from Anderson exist, the strength of the existing 30-year contract is such that it would be too costly to exit at this time. However, the District would not have to enter such an agreement for the other two sites if a more favorable revenue model existed.**

ORG/EXISTING AGREEMENT

Rates per Article 4
30 YR Contract signed 4/85
Rates @ Fixed Price Period Table B-1
12/88-12/98 for 1st 10 yrs of term
of Agreement. (Plant 1st
power generation 12/88)

12/98-12/28 Rates @ full
short term avoided operating
costs.

PACIFIC GAS AND ELECTRIC COMPANY

STANDARD OFFER #4

POWER PURCHASE AGREEMENT

FOR

LONG-TERM ENERGY AND CAPACITY

2 @ 470 KW

APRIL 1985

STANDARD OFFER #4
LONG-TERM ENERGY AND CAPACITY
POWER PURCHASE AGREEMENT

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Appendix B: ENERGY PAYMENT OPTIONS
Appendix C: CURTAILMENT OPTIONS
Appendix D: AS-DELIVERED CAPACITY
Appendix E: FIRM CAPACITY
Appendix F: INTERCONNECTION

LONG-TERM ENERGY AND CAPACITY
POWER PURCHASE AGREEMENT
BETWEEN
SANTA CLARA VALLEY WATER DISTRICT
AND
PACIFIC GAS AND ELECTRIC COMPANY

SANTA CLARA VALLEY WATER DISTRICT ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PGandE"), referred to collectively as "Parties" and individually as "Party", agree as follows:

ARTICLE 1 QUALIFYING STATUS

Seller warrants that, at the date of first power deliveries from Seller's Facility[1] and during the term of agreement, its Facility shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

---

[1] Underlining identifies those terms which are defined in Section A-1 of Appendix A.

ARTICLE 2 COMMITMENT OF PARTIES

The prices to be paid Seller for energy and/or capacity delivered pursuant to this Agreement have wholly or partly been fixed at the time of execution. Actual avoided costs at the time of energy and/or capacity deliveries may be substantially above or below the prices fixed in this Agreement. Therefore, the Parties expressly commit to the prices fixed in this Agreement for the applicable period of performance and shall not seek to or have a right to renegotiate such prices for any reason. As part of its consideration for the benefit of fixing part or all of the energy and/or capacity prices under this Agreement, Seller waives any and all rights to judicial or other relief fr its obligations and/or prices set forth in Appendices B, D, and E, or modification of any other term or provision for any reasons whatsoever.

This Agreement contains certain provisions which set forth methods of calculating damages to be paid to PGandE in the event Seller fails to fulfill certain performance obligations. The inclusion of such provisions is not intended to create any express or implied right in Seller to terminate this Agreement prior to the expiration of the term of agreement. Termination of this Agreement by Seller prior to its expiration date shall constitute a breach of this Agreement and the damages expressly set forth in this

Agreement shall not constitute PGandE's sole remedy for such breach.

ARTICLE 3 PURCHASE OF POWER

(a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of capacity and energy at the voltage level of 21 kV.

(b) Seller shall provide capacity and energy from its 800 kW Facility located at Anderson Dam, near Morgan Hill, Santa Clara County.

(c) The scheduled operation date of the Facility is January 1, 1987. At the end of each calendar quarter Seller shall give written notice to PGandE of any change in the scheduled operation date.

(d) To avoid exceeding the physical limitations of the interconnection facilities, Seller shall limit the Facility's actual rate of delivery into the PGandE system to _______ kW[1].

(e) The primary energy source for the Facility is water releases from Anderson Dam.

---

[1] To be determined upon execution of the Special Facilities Agreement for the Facility.

(f) If Seller does not begin construction of Facility by June 1, 1987, PGandE may reallocate the existing capacity on PGandE's transmission and/or distribution syste which would have been used to accommodate Seller's power deliveries to other uses. In the event of suc reallocation, Seller shall pay PGandE for the cost of any upgrades or additions to PGandE's system necessary to accommodate the output from the Facility. Such additional facilities shall be installed, owned and maintained in accordance with the applicable PGandE tariff.

(g) The transformer loss adjustment factor is ______[1].

ARTICLE 4 ENERGY PRICE

PGandE shall pay Seller for its net energy output[2] under the energy payment option checked below[3]:

__X__ Energy Payment Option 1 - Forecasted Energy Prices

---

[1] If Seller chooses to have meters placed on Seller's side of the transformer, an estimated transformer loss adjustment factor of 2 percent, unless the Parties agree otherwise, will be applied. This estimated transformer loss figure will be adjusted to a measurement of actual transformer losses performed at Seller's request and expense. To be determined upon execution of the Special Facilities Agreement for the Facility.

[2] Insert either "net energy output" or "surplus energy output" to show the energy sale option selected by Seller.

[3] Energy Payment Option 2 is not available to oil or gas-fired cogenerators.

Per Pg A-7
12/88- 12/98

During the fixed price period, Seller shall be paid for energy delivered at prices equal to 100[1] percent of the prices set forth in Table B-1, Appendix B, plus 0[2] percent of PGandE's full short-run avoided operating costs.

For the remaining years of the term of agreement, Seller shall be paid for energy delivered at prices equal to PGandE's full short-run avoided operating costs.

If Seller's Facility is not an oil or gas-fired cogeneration facility, Seller may convert from Energy Payment Option 1 to Energy Payment Option 2 and be subject to the conditions therein, provided that Seller shall not change the percentage of energy prices to be based on PGandE's full short-run avoided operating costs. Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

______ Energy Payment Option 2 - Levelized Energy Prices

---

[1] Insert either 0, 20, 40, 60, 80, or 100, at Seller's option. If Seller's Facility is an oil or gas-fired cogeneration facility, either 0 or 20 must be inserted.

[2] Insert the difference between 100 and the percentage selected under footnote 1 above.

During the fixed price period, Seller shall paid for energy delivered at prices equal to ________[1] percent of the levelized energy prices set forth in Table B-2, Appendix B for the year in which energy deliveries begin and term of agreement, plus ________[2] percent of PGandE's full short-run avoided operating costs. During the fixed price period, Seller shall be subject to the conditions and terms set forth in Appendix B, Energy Payment Option 2.

For the remaining years of the term of agreement, Seller shall be paid for energy delivered at prices equal to PGandE's full short-run avoided operati costs.

Seller may convert from Energy Payment Option 2 to Energy Payment Option 1, provided that Seller shall not change the percentage of energy prices to be based on PGandE's full short-run avoided operating costs. Such conversion must be made at least 90 days prior to the date of initial energy deliveries and must be made by written notice in accordance with Section A-17, Appendix A.

---

[1] Insert either 20, 40, 60, 80, or 100, at Seller's option.

[2] Insert the difference between 100 and the percentage selected unc footnote 1 above.

______ Energy Payment Option 3 - Incremental Energy Rate

Beginning with the date of initial energy deliveries and continuing until ______________[1], Seller shall be paid monthly for energy delivered at prices equal to PGandE's full short-run avoided operating costs, provided that adjustments shall be made annually to the extent set forth in Appendix B, Energy Payment Option 3.

The Incremental Energy Rate Band Widths specified by Seller in Table I below shall be used in determining the annual adjustment, if any.

Table I

Year	Incremental Energy Rate Band Widths (must be multiples of 100 or zero)
1984	______________
1985	______________
1986	______________
1987	______________
1988	______________
1989	______________
1990	______________
1991	______________
1992	______________
1993	______________
1994	______________
1995	______________
1996	______________
1997	______________
1998	______________

---

[1] Specified by Seller. Must be December 31, 1998 or prior.

After ______________, Seller shall be paid f energy delivered at prices equal to PGandE's full short-run avoided operating costs.

ARTICLE 5 CAPACITY ELECTION AND CAPACITY PRICE

Seller may elect to deliver either firm capacity or as-delivered capacity, and Seller's election is indicated below. PGandE's prices for firm capacity and as-delivered capacity are derived from PGandE's full avoided costs as approved by the CPUC.

X Firm capacity - ____[1] kW for 30 years from the firm capacity availability date with payment determined accordance with Appendix E. Except for hydroelectric facilities, PGandE shall pay Seller for capacity delivered in excess of firm capacity on an as-delivered capacity basis in accordance with As-Delivered Capacity Payment Option _______ set forth in Appendix D.

means PG&E pays for all power generated.

OR

______ As-delivered capacity with payment determined in accordance with As-Delivered Capacity Payment Option 2 set forth in Appendix D.

---

[1] To be determined by PGandE after submittal by Seller of theoretical operation study as referenced in Appendix , Section E-7.

ARTICLE 6 LOSS ADJUSTMENT FACTORS

Capacity Loss Adjustment Factors shall be as shown in Appendix D and Appendix E, dependent upon Seller's capacity election set forth in Article 5 of this Agreement.

Energy Loss Adjustment Factors shall be considered as unity for all energy payments related to Energy Payment Options 1 and 2 set forth in Appendix B for the entire fixed price period of this Agreement, except for the percentage of payments that Seller elected in Article 4 to have calculated based on PGandE's full short-run avoided operating costs. Energy Loss Adjustment Factors for all payments related to PGandE's full short-run avoided operating costs are subject to CPUC rulings for the entire term of agreement.

ARTICLE 7 CURTAILMENT

Seller has two options regarding possible curtailment by PGandE of Seller's deliveries, and Seller's selection is indicated below:

_X_ Curtailment Option A - Hydro Spill and Negative Avoided Cost

____ Curtailment Option B - Adjusted Price Period

The two options are described in Appendix C.

ARTICLE 8 RETROACTIVE APPLICATION OF CPUC ORDERS

Pursuant to Ordering Paragraph 1(f) of CPUC Decision No. 83-09-054 (September 7, 1983), after the effective date of the CPUC's Application 82-03-26 decision relating to line loss factors, Seller has the option to retain the relevant terms of this Agreement or have the results of that decision incorporated into this Agreement. To retain the terms herein, Seller shall provide written notice to PGandE within 30 days after the effective date of the relevant CPUC decision on Application 82-03-26. Failure to provide such notice will result in the amendment of this Agreement to comply with that decision.

As soon as practicable following the issuance of a decision in Application 82-03-26, PGandE shall notify Seller of the effective date thereof and its results.

ARTICLE 9 NOTICES

All written notices shall be directed as follows:

To PGandE:
Pacific Gas and Electric Company
Attention: Vice President -
Electric Operations
77 Beale Street
San Francisco, CA 94106

To Seller:
G. Thomas Dean
Santa Clara Valley Water District
5750 Almaden Expressway
San Jose, CA 95118

ARTICLE 10 DESIGNATED SWITCHING CENTER

The designated PGandE switching center shall be, unless changed by PGandE:

Edenvale
6402 Santa Teresa Boulevard
San Jose, CA
(408) 225-2677

ARTICLE 11 TERMS AND CONDITIONS

This Agreement includes the following appendices which are attached and incorporated by reference:

Appendix A - GENERAL TERMS AND CONDITIONS
Appendix B - ENERGY PAYMENT OPTIONS
Appendix C - CURTAILMENT OPTIONS
Appendix D - AS-DELIVERED CAPACITY
Appendix E - FIRM CAPACITY
Appendix F - INTERCONNECTION

ARTICLE 12 TERM OF AGREEMENT

This Agreement shall be binding upon execution and remain in effect thereafter for 30 years[1] from the firm capacity availability date[2]; provided, however, that it shall terminate if energy deliveries do not start within five years of the execution date.

---

[1] The minimum contract term is 15 years and the maximum contract term is 30 years.

[2] Insert "firm capacity availability date" if Seller has elected to deliver firm capacity or "date of initial energy deliveries" if Seller has elected to deliver as-delivered capacity.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and it is effective as of the last date set forth below.

SANTA CLARA VALLEY WATER DISTRICT	**PACIFIC GAS AND ELECTRIC COMPANY**
BY:	**BY:** EE Hall
JOSEPH H. DONOHUE	**E. E. HALL**
TITLE: Chairman, District Board of Directors	**TITLE:** Chief Generation Planning Engineer
DATE SIGNED: 4/16/85	**DATE SIGNED:** 4/17/85

APPENDIX A

GENERAL TERMS AND CONDITIONS

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APPENDIX A

GENERAL TERMS AND CONDITIONS

A-1 DEFINITIONS

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

Adjusted firm capacity price - The $/kW-year purchase price for firm capacity from Table E-2, Appendix E for the period of Seller's actual performance.

As-delivered capacity - Capacity delivered to PGandE in excess of firm capacity or in lieu of a firm capacity commitment.

CPUC - The Public Utilities Commission of the State of California.

Current firm capacity price - The $/kW-year capacity price from PGandE's firm capacity price schedule effective at the time PGandE derates the firm capacity pursuant to Section E-4(b), Appendix E or Seller terminates performance under this Agreement, for a term equal to the period from the date of deration or termination to the end of the term of agreement.

Designated PGandE switching center - That switching center or other PGandE installation identified in Article 10.

Facility - That generation apparatus described in Article 3 and all associated equipment owned, maintained, and operated by Seller.

Firm capacity - That capacity, if any, identified as firm in Article 5 except as otherwise changed as provided herein.

Firm capacity availability date - The day following the day during which all features and equipment of the Facility are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver firm capacity continuously into PGandE's system as provided in this Agreement.

Firm capacity price - The price for firm capacity applicable for the firm capacity availability date and the number of years of firm capacity delivery from the firm capacity price schedule, Table E-2, Appendix E.

Firm capacity price schedule - The periodical published schedule of the $/kW-year prices that PGan offers to pay for firm capacity. See Table E-2, Appendix E.

Fixed price period - The period during which forecasted or levelized energy prices, and/or forecasted as-delivered capacity prices, are in effect; defined as the first five years of the term of agreement if the term of agreement is 15 or 16 years; the first six years of the term of agreement if the term of agreement is 17, 18, or 19 years; or the first ten years of the term of agreement if the term of agreement is anywhere from 20 through 30 years.

Forced outage - Any outage resulting from a desi defect, inadequate construction, operator error or a breakdown of the mechanical or electrical equipment that fully or partially curtails the electrical output of the Facility.

Full short-run avoided operating costs - CPUC-approved costs which are the basis of PGandE's published energy prices. PGandE's current energy price calculation is shown in Table B-5, Appendix B. PGandE's published off-peak hours' prices shall be adjusted, as appropriate, if Seller has selected Curtailment Option B.

Interconnection facilities - All means required and apparatus installed to interconnect and deliver power from the Facility to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment, such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the Facility, and (2) the Facility from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. Interconnection facilities also include any necessary additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the Facility to the PGandE system.

Net energy output - The Facility's gross output in kilowatt-hours less station use and transformation and transmission losses to the point of delivery into the PGandE system. Where PGandE agrees that it is impractical to connect the station use on the generator side of the power purchase meter, PGandE may, at its option, apply a station load adjustment.

Prudent electrical practices - Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfull and with safety, dependability, efficiency, and economy.

Scheduled operation date - The day specified in Article 3(c) when the Facility is, by Seller's estimate, expected to produce energy that will be available for delivery to PGandE.

Special facilities - Those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the Facility as provided in this Agreement and those parts of the interconnection facilities which are owned and maintained by PGandE at Seller's request, including meteri and data processing equipment. All special facilities shal be owned, operated, and maintained pursuant to PGandE's electric Rule No. 21, which is attached hereto.

Station use - Energy used to operate the Facility's auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output - The Facility's gross output, in kilowatt-hours, less station use, and any other use

Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

30 YR

Term of agreement - The number of years this Agreement will remain in effect as provided in Article 12.

Voltage level - The voltage at which the Facility interconnects with the PGandE system, measured at the point of delivery.

A-2 CONSTRUCTION

A-2.1 Land Rights

Seller hereby grants to PGandE all necessary rights of way and easements, including adequate and continuing access rights on property of Seller, to install, operate, maintain, replace, and remove the special facilities. Seller agrees to execute such other grants, deeds, or documents as PGandE may require to enable it to record such rights of way and easements. If any part of PGandE's equipment is to be installed on property owned by other than Seller, Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain such rights of way and easements, Seller shal reimburse PGandE for all costs incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the Facility at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

(a) Seller shall design, construct, install, own, operate, and maintain all interconnection facilities, except special facilities, to the point of interconnection with the PGandE system as required for PGandE to receive capacity a energy from the Facility. The Facility and interconnectio facilities shall meet all requirements of applicable codes and all standards of prudent electrical practices and shall be maintained in a safe and prudent manner. A description of the interconnection facilities for which Seller is solely responsible is set forth in Appendix F, or if the interconnection requirements have not yet been determined at the time of the execution of this Agreement, the descriptio of such facilities will be appended to this Agreement at the time such determination is made.

(b) Seller shall submit to PGandE the design and all specifications for the interconnection facilities (exc special facilities) and, at PGandE's option, the Facility, for review and written acceptance prior to their release for construction purposes. PGandE shall notify Seller in writing of the outcome of PGandE's review of the design and specifications for Seller's interconnection facilities (and the Facility, if requested) within 30 days of the receipt of the design and all of the specifications for the interconnection facilities (and the Facility, if requested). Any flaws perceived by PGandE in the design and specifications for the interconnection facilities (and the Facility, if requested) will be described in PGandE's written notification. PGandE's review and acceptance of the design and specifications shall not be construed as confirming or endorsing the design and specifications or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such design and specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the interconnection facilities as may be reasonably required by PGandE to meet changing requirements of the PGandE system.

(c) In the event it is necessary for PGandE to install interconnection facilities for the purposes of this Agreement, they shall be installed as special facilities.

(d) Upon the request of Seller, PGandE shall provid a binding estimate for the installation of interconnection facilities by PGandE.

A-2.3 Meter Installation

(a) PGandE shall specify, provide, install, own, operate, and maintain as special facilities all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.

(b) Seller shall provide, construct, install, ow and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad switchgear, switchboards, cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

(c) PGandE shall permit meters to be fixed on PGandE's side of the transformer. If meters are placed on PGandE's side of the transformer, service will be provided at the available primary voltage and no transformer loss adjustment will be made. If Seller chooses to have meters placed on Seller's side of the transformer, an estimated transformer loss adjustment factor of 2 percent, unless Parties agree otherwise, will be applied.

A-3 OPERATION

A-3.1 Inspection and Approval

Seller shall not operate the Facility in parallel with PGandE's system until an authorized PGandE representative has inspected the interconnection facilities, and PGandE has given written approval to begin parallel operation. Seller shall notify PGandE of the Facility's start-up date at least 45 days prior to such date. PGandE shall inspect the interconnection facilities within 30 days of the receipt of such notice. If parallel operation is not authorized by PGandE, PGandE shall notify Seller in writing within five days after inspection of the reason authorization for parallel operation was withheld.

A-3.2 Facility Operation and Maintenance

Seller shall operate and maintain its Facility according to prudent electrical practices, applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the Facility at the power factors or voltage levels prescribed by PGandE's system dispatcher or designated representative. If Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-3.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors (or those of Seller's agent) contact PGandE's system as it shall exist whenever the deliveries are being made or at such other point or points as the Parties may agree in writing. The initial point of delivery of Seller's power to the PGandE system is set forth in Appendix F.

A-3.4 Operating Communications

(a) Seller shall maintain operating communications with the designated PGandE switching center. The operati communications shall include, but not be limited to, system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factors and daily capacity and generation reports.

(b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant events related to the operation of the Facility.

(c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graph recording device power in kW and voltage in kV at a location within the Facility agreed to by both Parties.

(d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the designated PGandE switching center, twice a day at agreed upon times for the current day's operation, the hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.

(e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also require Seller to telemeter transmission kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the designated PGandE switching center.

A-3.5 Meter Testing and Inspection

(a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.

(b) PGandE shall inspect and test all meters upc their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-3.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than t percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for -- (1) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-4 PAYMENT

PGandE shall mail to Seller not later than 30 d after the end of each monthly billing period (1) a statement showing the energy and capacity delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the amount due Seller, and (3) PGandE's check in payment of said amount. Except as provided in Section A-5, if within 30 days of receipt of the statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-5 ADJUSTMENTS OF PAYMENTS

(a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-3.6 to recompute the amount due from PGandE to Seller for the capacity and energy delivered under this Agreement during the period of inaccuracy.

(b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-6 ACCESS TO RECORDS AND PGandE DATA

Each Party, after giving reasonable written notice to the other Party, shall have the right of access to all metering and related records including operations logs c the Facility. Data filed by PGandE with the CPUC pursuan to CPUC orders governing the purchase of power from qualifying facilities shall be provided to Seller upon request; provided that Seller shall reimburse PGandE for the costs it incurs to respond to such request.

A-7 INTERRUPTION OF DELIVERIES

PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of energy (1) when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or any part of its system, or (2) if determines that interruption or reduction is necessa because of PGandE system emergencies, forced outages, force majeure, or compliance with prudent electrical practices; provided that PGandE shall not interrupt deliveries pursuant to this section in order to take advantage, or make purchases, of less expensive energy elsewhere. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

A-8 FORCE MAJEURE

(a) The term force majeure as used herein mea unforeseeable causes, other than forced outages, beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure including, but not limited to, acts of God, labor disputes, sudden actions of the elements, actions by federal, state, and municipal agencies, and actions of legislative, judicial, or regulatory agencies which conflict with the terms of this Agreement.

(b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:

(1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,

(2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,

(3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other

labor disputes shall be at the sole discretion of t
Party having the difficulty),

(4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect, and

(5) capacity payments during such periods of force majeure on Seller's part shall be governed by Section E-2(c), Appendix E.

(c) In the event a Party is unable to perform due to legislative, judicial, or regulatory agency action, this Agreement shall be renegotiated to comply with the legal change which caused the non-performance.

A-9 INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages including property of either Party resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of, or (2) the making of replacements, additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall ap
notwithstanding the active or passive negligence of the

indemnitee. Neither Party shall be indemnified hereunder for its liability or loss resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-10 LIABILITY; DEDICATION

(a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.

(b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities, and such other Party shall not be liable for any such damages so caused.

(c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public or affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-11 SEVERAL OBLIGATIONS

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-12 NON-WAIVER

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-13 ASSIGNMENT

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-14 CAPTIONS

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-15 CHOICE OF LAWS

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-16 GOVERNMENTAL JURISDICTION AND AUTHORIZATION

Seller shall obtain any governmental authorizations and permits required for the construction and operation of the Facility. Seller shall reimburse PGandE for any and all losses, damages, claims, penalties, or liability it incurs as a result of Seller's failure to obtain or maintain such authorizations and permits.

A-17 NOTICES

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing (except as provided in Section E-3) and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 9 of this Agreement. Changes in such designation may be made by notice similarly given.

A-18 INSURANCE

A-18.1 General Liability Coverage

(a) Seller shall maintain during the performance hereof, General Liability Insurance[1] of not less than $1,000,000 if the Facility is over 100 kW, $500,000 if the Facility is over 20 kW to 100 kW, and $100,000 if the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.

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[1] Governmental agencies which have an established record self-insurance may provide the required coverage throu self-insurance.

(b) General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

(c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured if the Facility is over 100 kW insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-18.2 Additional Insurance Provisions

(a) Evidence of coverage described above in Section A-18.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.

(b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

(c) Seller shall furnish the required certificates and endorsements to PGandE prior to commencing operation.

(d) All insurance certificates[1], endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager - Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94106

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[1] A governmental agency qualifying to maintain self-insuran should provide a statement of self-insurance.

APPENDIX B

ENERGY PAYMENT OPTIONS

Energy Payment Option 1 - Forecasted Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during each year of the fixed price period shall include the appropriate prices for such year in Table B-1, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the forecasted off-peak hours' energy prices listed in Table B-1 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B.

[redacted]

[redacted]

SUPERCEDED

[redacted]

[redacted]

THIS TABLE APPLIES FOR 1ST 10 YRS OF OPERATION

TABLE B-1

Forecasted Energy Price Schedule

Year of Energy Deliveries	Forecasted Energy Prices*, ¢/kWh Period A On-Peak	 Partial-Peak	 Off-Peak	 Period B On-Peak	 Partial-Peak	 Off-Peak	Weight Annual Average
1983	5.36	5.12	4.94	5.44	5.31	5.19	5.18
1984	5.66	5.40	5.22	5.74	5.61	5.48	5.47
1985	5.75	5.48	5.30	5.83	5.69	5.56	5.55
1986	5.99	5.72	5.52	6.08	5.94	5.80	5.79
1987	6.38	6.08	5.88	6.47	6.32	6.17	6.16
1988	6.94	6.62	6.39	7.03	6.87	6.71	6.70
1989	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1990	8.12	7.74	7.48	8.23	8.04	7.85	7.84
1991	8.64	8.24	7.96	8.75	8.56	8.35	8.34
1992	9.33	8.90	8.60	9.46	9.24	9.02	9.01
1993	10.10	9.63	9.30	10.23	10.00	9.76	9.75
1994	10.91	10.41	10.06	11.06	10.81	10.55	10.5
1995	11.79	11.25	10.87	11.96	11.68	11.40	11.35
1996	12.67	12.09	11.68	12.85	12.56	12.25	12.24
1997	13.61	12.98	12.54	13.79	13.48	13.15	13.14

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* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 2 - Levelized Energy Prices

Pursuant to Article 4, the energy payment calculation for Seller's energy deliveries during the fixed price period shall include the appropriate prices set forth in Table B-2 for the year in which energy deliveries begin and term of agreement, multiplied by the percentage Seller has specified in Article 4. If Seller has selected Curtailment Option B in Article 7, the levelized off-peak hours' energy prices listed in Table B-2 shall be adjusted upward by 7.7% for Period A and 9.6% for Period B. The discount specified in (c)(vi) below, if applicable, will be applied to the energy payments during the fixed price period.

During the fixed price period, Seller shall be subject to the following conditions and terms:

(a) Minimum Damages

The Parties agree that the levelized energy prices which PGandE pays Seller for the energy which Seller delivers to PGandE is based on the agreed value to PGandE of Seller's energy deliveries during the entire fixed price period. In the event PGandE does not receive such full performance by reason of a termination, Seller shall pay PGandE an amount based on the difference between the net present values, at the time of termination, of the payments Seller wou receive at the forecasted energy prices in Table B-1 and the payments Seller would receive at the levelized energy prices, for the remaining years of the fixed price period. This amount shall be calculated by assuming that Seller continued to generate for the remaining years of the fixed price period at a level equal to the average annual energy generation during the period of performance, and by applying the weighted annual average levelized price applicable to Seller's Facility and the weighted annual average forecasted energy prices in Table B-1 for the remaining years of the fixed price period. The following formula shall be used to make this calculation:

$$P = \sum_{n=1}^{Y} \frac{(F_n)(A)(W)}{(1.15)^n} - \sum_{n=1}^{Y} \frac{(L)(A)(W)}{(1.15)^n}$$

where:

P = amount due PGandE.

Y = number of years remaining in the fixed price period.

F_n = weighted annual average forecasted energy price in the nth year after the breach, failure to perform, or expiration of security, as shown in Table B-1 for corresponding calendar year.

L = weighted annual average levelized energy price applicable to Seller's Facility.

A = average annual energy generation by Seller during the period of performance.

n = summation index; refers to the $n^{\underline{th}}$ year following termination.

W = percent of Seller's energy payments based on the levelized energy prices, as specified in Article 4.

(b) Performance Requirements

Seller shall operate and maintain the Facility in accordance with prudent electrical practices in order to maximize the likelihood that the Facility's output as delivered to PGandE during the part of the fixed price period when the levelized price is below the forecasted price ("last part") shall equal or exceed 70% of the Facility's output during the part of the fixed price period when the levelized price is above the forecasted price ("first part"). In the event that the Facility's output during any year or series of years in the last part of the fixed price period is less than 70% of the average annual production during the first part of the fixed price period, PGandE may, at its discretion (taking into consideration events occurring during such year or series of years such as curtailment by PGandE, Seller's choice not to operate during adjusted price periods, or scheduled maintenanc including major overhauls, and the probability that Seller's future performance will be adequate), either request payment from Seller or immediately draw on the security posted, up to the amount equal to

$P \times \frac{A-B}{A}$, where:

P and A are as defined in Section (a) above.

B = Seller's average annual energy generation during the year or series of years in which the 70% performance requirement was not met.

PGandE shall not request payment from Seller or draw on the security posted if the Facility's output during t last part of the fixed price period falls below 70% of the average annual energy generation during the first part of the fixed price period solely because of force majeure as defined in Section A-8, Appendix A or a lack of or limited availability of the primary energy resource of the Facility, if such energy resource is wind, water, or sunlight.

(c) Security

(1) As security for amounts which Seller may be obligated to pay PGandE pursuant to Sections (and (b) above, Seller shall provide and mainta one or more of the following in an amount as

described in Section (c)(2) below.

(i) An irrevocable bank letter of credit delivered to and in favor of PGandE with terms acceptable to PGandE.

(ii) A payment bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(iii) Fully paid up, noncancellable Project Failure Insurance made payable to PGandE with terms of such policy(ies) acceptable to PGandE.

(iv) A performance bond providing for payment to PGandE in the event of any failure to meet the performance requirements set forth in Section (b) above or breach of this Agreement by Seller. Such bond shall be issued by a surety company acceptable to PGandE and shall have terms acceptable to PGandE.

(v) A corporate guarantee of payment to PGandE which PGandE deems, in its sole discretion, to provide at least the same quality security as subsections (i) through (iv) above.

(vi) Other forms of security which PGandE does not deem to be equivalent security to those listed in subsections (i) through (v) above, and which PGandE, in its sole discretion, deems adequate. Such other forms of security may include, for example, a corporate guarantee or a lien, mortgage or deed of trust on the Facility or land upon which it is located. A 1.5% discount will be applied against the levelized energy price portion PGandE's payments to Seller during the fixed price period if this type of security is provided.

(2) (i) Commencing 90 days prior to the scheduled operation date and continuing until December 1 of the following calendar year, security as described in Section (c)(1) above shall be in place in an amount calculated in accordance with the formula set forth in Section (a) above, assuming Seller delivered energy through the end of the following calendar year and then terminated th Agreement. For purposes of determining the

required amount of security, it shall be assumed that Seller's deliveries through the end of the following calendar year would equal R x C x H, where:

R = nameplate rating, in kW, of the Facility.

C = estimated capacity factor of the Facility, which shall be established by mutual agreement of the Parties at the time of execution of this Agreement.

H = number of hours from the scheduled operation date through the end of the following calendar year.

(ii) In the second calendar year of operation and each year thereafter until the end of the fixed price period, from December 1 through December 1 of the following year, security shall be in place in an amount calculated by the formula set forth in Section (a) above assuming Seller continued to deliver energy in each month through the end of the following calendar year, at a level equal to the average monthly energy deliveries to date, and then terminated this Agreement.

(3) Security must be maintained throughout the fixed price period as specified above. Any security with a fixed expiration date must be renewed by Seller prior to that date. If such security is not renewed at least 30 days prior to its expiration, PGandE may, at its discretion, either request payment from Seller or immediately draw on the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above.

(4) If, at any time during the fixed price period, PGandE believes Seller is in material breach of this Agreement, PGandE shall so notify Seller in writing and Seller must remedy such breach within a reasonable period of time. If Seller does not so remedy, PGandE may, at its discretion, either request payment from Seller or immediately draw upon the security posted, up to the amount calculated in accordance with the formula set forth in Section (a) above, provided that if during Seller's period to remedy, Seller disputes PGandE's conclusion that Seller is in material breach, and PGandE elects to draw upon the security, the amount drawn upon by PGandE shall be deposited in an interest earning escrow account and held in such account until the dispute is resolved in accordance with Section (c)(5) below.

(5) Upon the written request of either Party, any controversy or dispute between the Parties concerning Section (c)(4) above shall be subject to arbitration in accordance with the provisions of the California Arbitration Act, Sections 1280-1294.2 of the California Code of Civil Procedure except as provided otherwise in this section. Either Party may demand arbitration by first giving written notice of the existence of a dispute and then within 30 days of such notice giving a second written notice of the demand for arbitration.

Within ten days after receipt of the demand for arbitration, each Party shall appoint one person, who shall not be an employee of either Party, to hear and determine the dispute. After both arbitrators have been appointed, they shall within five (5) days select a third arbitrator.

The arbitration hearing shall take place in San Francisco, California, within 30 days of the appointment of the arbitrators, at such time and place as they select. The arbitrators shall give written notice of the time of the hearing to both Parties at least ten days prior to the hearing. The arbitrators shall not be authorized to alter, extend, or modify the terms of this Agreement. At the hearing, each Party shall submit a propose written decision, and any relevant evidence may be presented. The decision of the arbitrators must consist of selection of one of the two proposed decisions, in its entirety.

The decision of any two arbitrators shall be binding and conclusive as to disputes relating to Section (c)(4) only. Upon determining the matter, the arbitrators shall promptly execute and acknowledge their decision and deliver a copy to each Party. A judgment confirming the award may be rendered by any superior court having jurisdiction. Each Party shall bear its c arbitration costs and expenses, including the cost of the arbitrator it selected, and the costs and expenses of the third arbitrator shall be divided equally between both Parties, except as provided otherwise elsewhere in this Agreement.

Pending resolution of any controversy or dispute hereunder, performance by each Party shall continue so as to maintain the status quo prior to notice of such controversy or dispute. Resolutio of the controversy or dispute shall include payment of any interest accrued in the escrow account.

TABLE B-2
Levelized Energy Price Schedule

For a term of agreement of 15-16 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.76	5.50	5.31	5.85	5.71	5.58	5.57
1984	6.06	5.78	5.58	6.14	6.00	5.86	5.85
1985	6.41	6.11	5.91	6.50	6.35	6.20	6.19
1986	6.85	6.54	6.32	6.95	6.79	6.63	6.62
1987	7.37	7.03	6.79	7.47	7.30	7.13	7.12
1988	7.96	7.60	7.34	8.07	7.89	7.70	7.69

For a term of agreement of 17-19 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	5.90	5.63	5.44	5.98	5.84	5.71	5.70
1984	6.23	5.95	5.74	6.32	6.18	6.03	6.02
1985	6.60	6.30	6.08	6.69	6.53	6.38	6.37
1986	7.06	6.73	6.51	7.16	7.00	6.83	6.82
1987	7.60	7.25	7.00	7.70	7.53	7.35	7.34
1988	8.21	7.83	7.57	8.32	8.13	7.94	7.93

For a term of agreement of 20-30 years:

Year in Which Energy Deliveries Begin	Levelized Energy Prices*, ¢/kWh						Weighted Annual Average
	Period A			Period B			
	On-Peak	Partial-Peak	Off-Peak	On-Peak	Partial-Peak	Off-Peak	
1983	6.49	6.20	5.98	6.58	6.43	6.28	6.27
1984	6.90	6.58	6.35	6.99	6.83	6.67	6.66
1985	7.34	7.00	6.76	7.44	7.27	7.10	7.09
1986	7.88	7.51	7.26	7.99	7.81	7.62	7.61
1987	8.49	8.10	7.82	8.61	8.41	8.21	8.20
1988	9.16	8.74	8.44	9.29	9.08	8.86	8.85

---

* These prices are differentiated by the time periods as defined in Table B-4.

Energy Payment Option 3 - Incremental Energy Rat

During the period specified in Article 4, annual adjustments to Seller's energy payments shall be made as described below.

At the end of each calendar year, the Derived Incremental Energy Rate (with units expressed in Btu/kWh) will be calculated as follows:

$$\text{Derived Incremental Energy Rate (DIER)} = \frac{B}{A \times C}$$

where:

A = the total kWh delivered by Seller during ti calendar year, excluding any kWh delivered when Seller was asked to curtail deliveries under Curtailment Option A or when Seller was asked to take adjusted prices under Curtailment Option B.

B = the total dollars paid for the energy described for A above.

C = the weighted average price paid during the calendar year by PGandE's Electric Department for oil and natural gas for PGandE's fossil steam plants, expressed in $/Btu on a gas Btu basis.

If the DIER is between the upper and lower Incremental Energy Rate Bounds specified for that year in Table B-3 for the curtailment option selected by Seller, no additional payment is due either Party.

If the DIER is below the lower Incremental Energy Rate Bound, PGandE shall pay Seller an amount calculated as follows:

$$P_S = (\text{Lower Incremental Energy Rate Bound} - \text{DIER})(A)(C)$$

where:

P_S = additional payment due Seller.
DIER = Derived Incremental Energy Rate.

PGandE shall add this payment to the first payment made to Seller following the calculation.

If the DIER is above the upper Incremental Energy Rate Bound, Seller shall pay PGandE an amount calculated as follows:

$$P_B = (\text{DIER} - \text{Upper Incremental Energy Rate Bound})(A)(C)$$

where:

P_B = amount due PGandE.
DIER = Derived Incremental Energy Rate.

This amount shall be deducted from the first payment made to Seller following the calculation. If there is any remaining amount due PGandE, PGandE may, at its option, invoice Seller with such payment due within 30 days or deduct this amount from future payments due Seller.

TABLE B-3

Forecasted Incremental Energy Rates and Incremental Energy Rate Bounds

Curtailment Option A:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column(b)]
1984	9,000	________	________	________
1985	9,050	________	________	________
1986	8,840	________	________	________
1987	8,850	________	________	________
1988	8,960	________	________	________
1989	8,820	________	________	________
1990	8,540	________	________	________
1991	8,540	________	________	________
1992	8,540	________	________	________
1993	8,540	________	________	________
1994	8,540	________	________	________
1995	8,540	________	________	________
1996	8,540	________	________	________
1997	8,540	________	________	________
1998	8,540	________	________	________

TABLE B-3 (continued)

Curtailment Option B:

Year	Forecasted Incremental Energy Rates, Btu/kWh (a)	Incremental Energy Rate Band Width from Article 4, Btu/kWh (b)	Upper Incremental Energy Rate Bound, Btu/kWh [column (a) plus column (b)]	Lower Incremental Energy Rate Bound, Btu/kWh [column (a) minus column(b)]
1984	9,440			
1985	9,500			
1986	9,280			
1987	9,290			
1988	9,400			
1989	9,270			
1990	8,970			
1991	8,970			
1992	8,970			
1993	8,970			
1994	8,970			
1995	8,970			
1996	8,970			
1997	8,970			
1998	8,970			

TABLE B-4[1]
Time Periods

	Monday through Friday[2]	Saturdays[2]	Sundays and Holidays
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		
Partial-Peak	8:30 a.m. to 12:30 p.m. 6:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m. 8:30 a.m. to 4:30 p.m.	8:30 a.m. to 10:30 p.m.	
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

---

[1] This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

[2] Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

TABLE B-5

ENERGY PRICES

Energy Prices Effective February 1 - April 30, 1985

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during February, March, and April 1985 are as follows:

Time Period	(a) Incremental Energy Rate[1] (Btu/kWh)	(b) Cost of Energy[2] ($/$10^6$ Btu)	(c) Revenue Requirement for Cash Working Capital[3] ($/kWh)	(d) Energy Purchase Price[4] (d) = [(a) x (b)] + (c) ($/kWh)
February 1 - April 30 (Period B)				
Time of Delivery Basis:				
On-Peak	16,320	5.2394	0.00053	0.08604
Partial-Peak	15,689	5.2394	0.00051	0.08271
Off-Peak	11,625	5.2394	0.00038	0.06129
Seasonal Average (Period B)	13,692	5.2394	0.00045	0.07219

---

[1] Incremental energy rates (Btu/kWh) for Seasonal Period A and Seasonal Period B are derived from the marginal energy costs (including variable operating and maintenance expense) adopted by the CPUC in Decision No. 83-12-068 (page 339). They are based upon natural gas as the incremental fuel and weighted average hydroelectric power conditions.

[2] Cost of natural gas under PGandE Gas Schedule No. G-55 effective February 1, 1985 per Advice No. 1304-G.

[3] Revenue Requirement for Cash Working Capital as prescribed by the CPUC in Decision No. 83-12-068.

[4] Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of CPUC Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The currently applicable energy loss adjustment factors are shown in Table B-6.

TABLE B-6

Energy Loss Adjustment Factors[1]

	Transmission	Primary Distribution	Secondary Distribution
Seasonal Period A (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
Seasonal Period B (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

---

[1] The applicable energy loss adjustment factors may be revised pursuant to orders of the CPUC.

APPENDIX C

CURTAILMENT OPTIONS

Seller has two options regarding curtailment of energy deliveries and Seller has made its selection in Article 7. The two options are as follows:

CURTAILMENT OPTION A - HYDRO SPILL AND NEGATIVE AVOIDED COST

(a) In anticipation of a period of hydro spill conditions, as defined by the CPUC, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such perio Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

$$\frac{AQF - S}{AQF} \times PP \qquad (\geq 0)$$

where:

AQF = Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provision

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period.

(b) PGandE shall not be obligated to accept or pay for and may require Seller with a Facility with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy during periods when PGandE would incur negative avoided costs (as defined by the CPUC) due to continued acceptance of energy deliveries under this Agreement. Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

(c) Before interrupting or reducing deliveries under subsection (b), above, and before invoking hydro savings prices under subsection (a), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy condition exists Seller shall be paid at the economy sales price obtained by PGandE i lieu of the otherwise applicable prices.

(d) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (a) or when PGandE curtails deliveries of energy pursuant to subsection (b), Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE. If Seller is selling surplus energy output to PGandE, subsections (a) or (b) shall only apply to the surplus energy output being delivered to PGandE, and Seller can continue to internally use that generation it ha retained for its own use.

CURTAILMENT OPTION B - ADJUSTED PRICE PERIOD

(a) In each calendar year, the price which PGandE is obligated to pay Seller for energy deliveries during 1,000 off-peak hours (as defined in Table B-4, Appendix B) may be adjusted to a price equal to, but not in excess of, PGandE's available alternative source. This adjusted price shall be effective under any of the following conditions:

(i) when PGandE's energy source at the margin is not a PGandE oil- or gas-fueled plant, and PGanc can replace Seller's energy with energy from this source at a cost less than the price paid to Seller;

(ii) when PGandE would incur negative avoided costs (as defined by the CPUC) due to continued acceptance of energy deliveries under this Agreement; or

(iii) when PGandE is experiencing minimum system operations.

During any of the conditions described above the adjusted price may be zero.

(b) Whenever possible, PGandE shall give Seller reasonable notice of any price adjustment for energy deliveries and its probable duration.

(c) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE and Seller elects not to sell energy to PGandE at the adjusted price, Seller shall not use such energy to meet its electrical needs but shall continue to purchase all its electrical needs from PGandE.

(d) After Seller receives notice of the probable duration of the period during which the adjusted price will be paid, Seller may elect to perform maintenance during such period and so inform the PGandE employee in charge at th designated PGandE switching center prior to the time when the adjusted price period is expected to begin. If Seller makes such election, the number of off-peak hours of probable duration quoted in PGandE's notice to Seller shall be applied to the 1,000-hour calendar year limitation set forth in this section. After an election to do maintenance, if Seller makes any deliveries of energy during the quoted probable duration period, Seller shall be paid the adjusted price quoted in its notice from PGandE without regard to any subsequent changes on the PGandE system which may alter the adjusted price or shorten the actual duration of the condition.

APPENDIX D

AS-DELIVERED CAPACITY

D-1 AS-DELIVERED CAPACITY PAYMENT OPTIONS

Seller has two options for as-delivered capacity payments and Seller has made its selection in Article 5. The two options are as follows:

AS-DELIVERED CAPACITY PAYMENT OPTION 1

PGandE shall pay Seller for as-delivered capacity at prices authorized from time to time by the CPUC. The as-delivered capacity prices in effect on the date of execution are calculated as shown in Exhibit D-1.

AS-DELIVERED CAPACITY PAYMENT OPTION 2

During the fixed price period, the as-delivered capacity prices will be calculated in accordance with Exhibit D-1 and the forecasted shortage costs in Table D-2.

For the remaining years of the term of agreement, PGandE shall pay Seller for as-delivered capacity at the higher of:

(i) prices authorized from time to time by the CPUC;

(ii) the as-delivered capacity prices that were paid Seller in the last year of the fixed price period; or

(iii) the as-delivered capacity prices in effect in the first year following the end of the fixed price period, provided that the annualized shortage cost from which these prices are derived does not exceed the annualized valu of a gas turbine.

D-2 AS-DELIVERED CAPACITY IN EXCESS OF FIRM CAPACITY

The amount of capacity delivered in excess of firm capacity will be considered as-delivered capacity. This as-delivered capacity is based on the total kilowatt-hours delivered each month during all on-peak, partial-peak and off-peak hours excluding any energy associated with generation levels equal to or less than the firm capacity.

Seller has the two options listed in Section D-1 fo payment for such as-delivered capacity. Seller has made i selection in Article 5.

EXHIBIT D-1

The as-delivered capacity price (in cents per kW-hr) for power delivered by the Facility is the product of three factors:

(a) The shortage cost in each year the Facility is operating. Currently, this shortage cost is $60 per kW-year.

(b) A capacity loss adjustment factor which provides for the effect of the deliveries on PGandE's transmission and distribution losses based on the Seller's interconnection voltage level. The applicable capacity loss adjustment factors for non-remote[1] Facilities are presented in Table D-1(a). Capacity loss adjustment factors for remote Facilities shall be calculated individually.

(c) An allocation factor which accounts for the different values of as-delivered capacity in different time periods and converts dollars per kW-year to cents per kWh. The current allocation factors are presented in Table D-1(b). The time periods to which they apply are shown in Table B-4, Appendix B. The allocation factors are subject to change from time to time.

---

[1] As defined by the CPUC.

TABLE D-1(a)

Capacity Loss Adjustment Factors for Non-Remote[1] Facilities

Voltage Level	Loss Adjustment Factor
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote, the capacity loss adjustment factor is ______________[2].

TABLE D-1(b)

Allocation Factors for As-Delivered Capacity[3]

	On-Peak (¢-yr/$-hr)	Partial-Peak (¢-yr/$-hr)	Off-Peak (¢-yr/$-hr)
Seasonal Period A	.10835	.02055	.00002
Seasonal Period B	.00896	.00109	.00001

---

[1] As defined by the CPUC. The capacity loss adjustment factors for remote Facilities are determined individually.

[2] Determined individually.

[3] The units for the allocation factor, ¢-yr/$-hr, are derived from the conversion of $/kW-yr into ¢/kWh as follows:

$$\frac{\text{¢/kWh}}{\text{\$/kW-yr}} = \frac{\text{¢/kW-hr}}{\text{\$/kW-yr}} = \frac{\text{¢-yr}}{\text{\$-hr}}$$

The allocation factors were prescribed by the CPUC in Decision No. 83-12-068 and are subject to change from time to time.

TABLE D-2

Forecasted Shortage Cost Schedule

Year	Forecast Shortage Cost, $/kW-Yr
1983	70
1984	76
1985	81
1986	88
1987	95
1988	102
1989	110
1990	118
1991	126
1992	135
1993	144
1994	154
1995	164
1996	176
1997	188

APPENDIX E

FIRM CAPACITY

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APPENDIX E

FIRM CAPACITY

E-1 GENERAL

This Appendix E establishes conditions and prices under which PGandE shall pay for firm capacity.

PGandE's obligation to pay for firm capacity shall begin on the firm capacity availability date. The firm capacity price shall be subject to adjustment as provided for in this Appendix E.

The firm capacity prices in Table E-2 are applicable for deliveries of firm capacity beginning after December 30, 1982.

E-2 PERFORMANCE REQUIREMENTS

(a) To receive full capacity payments, the firm capacity shall be delivered for all of the on-peak hours[1] in the peak months on the PGandE system, which are presently the months of June, July, and August, subject to a 20 percent allowance for forced outages in any month. Compliance with this provision shall be based on the Facility's total on-peak deliveries for each of the peak months and shall exclude any energy associated wit generation levels greater than the firm capacity.

---

[1] On-peak, partial-peak, and off-peak hours are defined in Table B-4, Appendix B.

(b) If Seller is prevented from meeting the performance requirements because of a forced outage on the PGandE system, a PGandE curtailment of Seller's deliveries, or a condition set forth in Section A-7, Appendix A, PGandE shall continue capacity payments. Firm capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(c) If Seller is prevented from meeting the performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from tl occurrence of the force majeure. Thereafter, Seller shall be deemed to have failed to have met the performance requirements. Firm capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(d) If Seller is prevented from meeting the performance requirements because of exteme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish firm capacity pursuant to Section E-8. Seller shall warrant to PGandE that the Facility is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its firm capacity obligations.

(e) If Seller is prevented from meeting the performance requirements for reasons other than those described above in Sections E-2(b), (c), or (d):

(1) Seller shall receive the reduced firm capacity payments as provided in Section E-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.

(2) If, at the end of the probationary period Seller has not demonstrated that the Facility can meet the performance requirements, PGandE may derate the firm capacity pursuant to Section E-4(b).

E-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 9, within 24 hours of the original notice, all notices Seller gives personally or by telephone for scheduled maintenance.

If Seller has selected Curtailment Option B, off-peak hours of maintenance performed pursuant to Section (d) of Curtailment Option B, Appendix C shall not be deducted from Seller's scheduled maintenance allowances set forth above.

E-4 ADJUSTMENTS TO FIRM CAPACITY

(a) Seller may increase the firm capacity with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.

(b) Seller may reduce the firm capacity at any time prior to the firm capacity availability date by giving written notice thereof to PGandE. PGandE may derate the firm capacity in accordance with Section E-2(e) as a result of appropriate data showing Seller has failed to meet the performance requirements of Section E-2.

E-5 FIRM CAPACITY PAYMENTS

The method for calculation of firm capacity payments is shown below. As used below in this section, month refers to a calendar month.

The monthly payment for firm capacity will be the product of the Period Price Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table E-1 based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table E-3, plus any allowable payment for outages due to scheduled maintenance. The firm capacity price shall be applied to meter readings taken during the separate times and periods as illustrated in Table B-4, Appendix B.

The PPF is determined by multiplying the firm capacity price by the following Allocation Factors[1]:

	Allocation Factor	x	Firm Capacity Price	=	PPF (\$/kW-month)
Seasonal Period A	.18540		____________		____________
Seasonal Period B	.01043		____________		____________

---

[1] These allocation factors were prescribed by the CPUC in Decision No. 83-12-068. All allocation factors are subject to change by PGandE based on PGandE's marginal capacity cost allocation, as determined in general rate case proceedings before the CPUC. Seasonal Periods A and B are defined in Table B-4, Appendix B.

The MDC is determined in the following manner:

(1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B-S) \times (0.8^{*})} \qquad (\leq 1.0)$$

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the firm capacity.

C = Firm capacity in kilowatts.

B = Total on-peak and partial-peak hours during the month.

S = Total on-peak and partial-peak hours during the month Facility is out of service on scheduled maintenance.

(2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

$$MCF = P \times (1.0 - \frac{M}{D})$$

Where:

M = The number of hours during the month Facility is out of service on scheduled maintenance.

D = The number of hours in the month.

---

* 0.8 reflects a 20% allowance for forced outage.

(3) Determine the MDC by multiplying the MCF by C:

MDC (kilowatts) = MCF x C

The monthly payment for firm capacity is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table E-1, and by the appropriate performance bonus factor, if any, from Table E-3.

$$\text{monthly payment for firm capacity} = \text{PPF} \times \text{MDC} \times \text{capacity loss adjustment factor} \times \text{performance bonus factor}$$

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the product of the average hourly firm capacity payment[1] for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. Firm capacity payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section E-3 are met.

During a probationary period Seller's monthly payment for firm capacity shall be determined by substituting for the firm capacity, the capacity at which

---

[1] Total monthly payment divided by the total number of hours in the monthly billing period.

Seller would have met the performance requirements. In th event that during the probationary period Seller does not meet the performance requirements at whatever firm capacity was established for the previous month, Seller's monthly payment for firm capacity shall be determined by substituting the firm capacity at which Seller would have met the performance requirements. The performance bonus factor shall not be applied during probationary periods.

TABLE E-1

If the Facility is non-remote[1] the firm capacity los adjustment factors are as follows:

Voltage Level	Loss Adjustment Factor
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote the firm capacity loss adjustment factor is ____________[2].

---

[1] As defined by the CPUC.

[2] Determined individually.

TABLE E-2

Firm Capacity Price Schedule

(Levelized $/kW-year)

Firm Capacity Availability Date	Number of Years of Firm Capacity Delivery																	
(Year)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1982	65	68	70	72	75	77	79	81	84	86	88	90	91	93	95	103	109	113
1983	70	73	75	78	80	83	85	88	90	92	94	96	98	100	102	110	117	122
1984	76	78	81	84	86	89	92	94	97	99	101	103	106	108	110	118	125	130
1985	81	84	87	90	93	96	99	101	104	106	109	111	113	115	118	127	134	140
1986	88	91	94	97	100	103	106	109	112	114	117	119	122	124	126	136	144	150
1987	95	98	101	105	108	111	114	117	120	123	125	128	130	133	135	146	154	160

TABLE E-3

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for firm capacity delivered by the Facility after it has demonstrated a firm capacity factor in excess of 85%.

DEMONSTRATED FIRM CAPACITY FACTOR (%)	PERFORMANCE BONUS FACTOR
85	1.000
90	1.059
95	1.118
100	1.176

After the Facility has delivered power during the span of all of the peak months on the PGandE system (presently June, July, and August) in any year (span),

(i) the firm capacity factor for each such month shall be calculated in the following manner:

$$\text{FIRM CAPACITY FACTOR (\%)} = \frac{F}{(N-W) \times Q} \times 100$$

Where:

F = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding a. energy associated with generation levels greater than the firm capacity.

N = Total on-peak hours during the month.
W = Total on-peak hours during the peak month that the Facility is out of service on scheduled maintenance.
Q = Firm capacity in kilowatts.

(ii) the arithmetic average of the above firm capacity factors shall be determined for that span,

(iii) the average of the above arithmetic average firm capacity factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Firm Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Firm Capacity Factor not shown in Table E-3 use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Firm Capacity Factor (\%)}}{85\%}$$

SECTIONS E-6 THROUGH E-10 SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS

E-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section E-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the dat from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

E-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed un Section E-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to --

(1) Release requirements for support of fish life and any other operating constraints imposed on the project;

(2) Operating characteristics of the proposed equipment of the Facility such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;

(3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc.; and

(4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the Facility has water storage characteristics. For the study to show monthly capacity ratings, the Facility shall be capable of operating during all on-peak hours in the peak months on the PGandE system, which are presently the months of June, July, and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

E-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATING

Based on the results of the theoretical operation study developed under Section E-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity ratings from each month of those years. The firm capacity shown in Article 5 shall not exceed the lowest average dry year monthly capacity ratings for the peak months on the PGand system, which are presently the months of June, July, an August.

E-9 INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

(1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table E-4;

(2) A topographic project map which shows the location of all aspects of the Facility and locations of stream gauging stations used to determine natural flow data;

(3) A discussion of all major factors relevant to project operation;

(4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section E-6 and are consistent with generally accepted engineering practices; and

(5) Upon specific written request by PGandE, Seller's theoretical operation study.

E-10 ILLUSTRATIVE EXAMPLE

(1) Determine natural flows - These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication "Water Resources Data for California".

(2) Perform theoretical operation study - Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This study is performed based on the Facility's design, operating capabilities, constraints, etc., and should take into account all factors relevant to project

operation. Generally such a study is done by computer whic routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.

(3) Determine average dry year capacity ratings - After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years arrive at a monthly average capacity rating. The fi capacity is then set by the Seller based on the monthly average dry year capacity ratings and the performance requirements of this appendix. An example project is shown in the attached completed Table E-4.

EXAMPLE
TABLE E-4

Summary of Theoretical Operation Study

Project: New Creek 1

Water Source: West Fork New Creek

Mode of Operation: Run of the river

Type of Turbine: Francis Design Flow: 100 cfs Design Head: 150 feet

Operating Characteristics[1]:

	Flow (cfs)	Head (feet) Gross	Net	Output (kW)	Efficiency (%) Turbine	Generator
Normal Operation	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation - Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100
July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum firm capacity: 410 kW

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[1] If Facility has a variable head, operating curves should be provided.

E-11 MINIMUM DAMAGES

(a) In the event the firm capacity is derated o Seller terminates this Agreement, the quantity by which th firm capacity is derated or the firm capacity shall be u e to calculate the payments due PGandE in accordance w h Section (d).

(b) Seller shall be invoiced by PGandE for all amou s due under this section. Payment shall be due within 30 da s of the date of invoice.

(c) If Seller does not make payments pursuant o Section (b), PGandE shall have the right to offset amounts due it against any present or future payments d e Seller.

(d) Seller shall pay to PGandE:

(i) an amount equal to the differen between (a) the firm capacity payments already paid by PGandE, based on the original term agreement and (b) the total firm capacity payments which PGandE would have paid based on the peri of Seller's actual performance using the adjuste firm capacity price. Additionally, Seller sha pay interest, compounded monthly from the date excess capacity payment was made until the date

Seller repays PGandE, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate; plus

(ii) a sum equal to the amount by which the firm capacity is being terminated or derated times the difference between the current firm capacity price on the date of termination or deration for a term equal to the balance of the term of agreement and the firm capacity price, multiplied by the appropriate factor shown in Table E-5 below. In the event that the current firm capacity price is less than the firm capacity price, no payment under this subsection (ii) shall be due either Party.

TABLE E-5

Amount of Firm Capacity Terminated or Derated	Factor
1,000 kW or under	0.25
over 1,000 kW through 10,000 kW	0.75
over 10,000 kW through 25,000 kW	1.00
over 25,000 kW through 50,000 kW	3.00
over 50,000 kW through 100,000 kW	4.00
over 100,000 kW	5.00

APPENDIX F

INTERCONNECTION

CONTENTS

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F-1 INTERCONNECTION TARIFFS

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.)

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION

This describes the minimum operation, metering and interconnection requirements for any generating source or sources paralleled with the Utility's electric system. Such source or sources may include, but are not limited to, hydroelectric generators, wind-turbine generators, steam or gas driven turbine generators and photovoltaic systems.

A. GENERAL

1. The type of interconnection and voltage available at any location and the Utility's specific interconnection requirements shall be determined by inquiry at the Utility's local office.

2. The Utility's distribution and transmission lines which are an integral part of its overall system are distinguished by the voltages at which they are operated. Distribution lines are operated at voltages below 60 kv and transmission lines are operated at voltages 60 kv and higher.

3. The Power Producer (Producer) shall ascertain and be responsible for compliance with the requirements of all governmental authorities having jurisdiction.

4. The Producer shall sign the Utility's written form of power purchase agreement or parallel operation agreement before connecting or operating a generating source in parallel with the Utility's system.

5. The Producer shall be fully responsible for the costs of designing, installing, owning, operating and maintaining all interconnection facilities defined in Section B.1.

6. The Producer shall submit to the Utility, for the Utility's review and written acceptance, equipment specifications and detailed plans for the installation of all interconnection facilities to be furnished by the Producer prior to their purchase or installation. The Utility's review and written acceptance of the Producer's equipment specifications and detailed plans shall not be construed as confirming or endorsing the Producer's design or as warranting the equipment's safety, durability or reliability. The Utility shall not, by reason of such review or lack of review, be responsible for strength, details of design adequacy, or capacity of equipment built pursuant to such specifications, nor shall the Utility acceptance be deemed an endorsement of any such equipment.

7. No generating source shall be operated in parallel with the Utility's system until the interconnection facilities have been inspected by the Utility and the Utility has provided written approval to the Producer.

8. Only duly authorized employees of the Utility are allowed to connect Producer-installed interconnection facilities to, or disconnect the same from, the Utility's overhead or underground lines.

B. INTERCONNECTION FACILITIES

1. GENERAL: Interconnection facilities are all means required, and apparatus installed, to interconnect the Producer's generation with the Utility's system. Where the Producer desires to sell power to the Utility, interconnection facilities are also all means required, and apparatus installed, to enable the Utility to receive power deliveries from the Producer. Interconnection facilities may include, but are not limited to:
   a. connection, transformation, switching, metering, communications, control, protective and safety equipment; and
   b. any necessary additions to and reinforcements of the Utility's system by the Utility.

2. METERING
   a. A Producer desiring to sell power to the Utility shall provide, install, own and maintain all facilities necessary to accommodate metering equipment specified by the Utility. Such metering equipment may include meters, telemetering (applicable where deliveries to the Utility exceed 10 MW) and other recording and communications devices as may be required for the reporting of power delivery data to the Utility. Except as provided for in Section B.2.b following, the Utility shall provide, install, own and maintain all metering equipment as special facilities in accordance with Section F.

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RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

B. INTERCONNECTION FACILITIES (continued)

2. METERING

b. The Producer may at its option provide, install, own and maintain current and potential transformers rated above 600 volts and a non-revenue type graphic recorder where applicable. Such metering equipment, its installation and maintenance shall all be in conformance with the Utility's specifications.

c. The Utility's meters shall be equipped with detents to prevent reverse registration so that power deliveries to and from the Producer's equipment can be separately recorded.

3. CONTROL, PROTECTION AND SAFETY EQUIPMENT

a. GENERAL: The Utility has established functional requirements essential for safe and reliable parallel operation of the Producer's generation. These requirements provide for control, protective and safety equipment to:
(1) sense and properly react to failure and malfunction on the Utility's system;
(2) assist the Utility in maintaining its system integrity and reliability; and
(3) protect the safety of the public and the Utility's personnel.

b. Listed below are the various devices and features generally required by the Utility as a prerequisite to parallel operation of the Producer's generation:

CONTROL, PROTECTION AND SAFETY EQUIPMENT GENERAL REQUIREMENTS[1]

	GENERATOR SIZE					
Device or Feature	10 kw or Less	11 kw to 40 kw	41 kw to 100 kw	101 kw to 400 kw	401 kw to 1,000 kw	Over 1,000 k
Dedicated Transformer[2]	-	X	X	X	X	X
Interconnection Disconnect Device	X	X	X	X	X	X
Generator Circuit Breaker	X	X	X	X	X	X
Over-voltage Protection	X	X	X	X	X	X
Under-voltage Protection	-	-	X	X	X	X
Under/Over-frequency Protection	X	X	X	X	X	X
Ground Fault Protection	-	-	X	X	X	X
Over-current Relay w/Voltage Restraint	-	-	-	-	X	X
Synchronizing[3]	Manual	Manual	Manual	Manual	Manual	Automat
Power Factor or Voltage Regulation			X	X	X	X

c. DISCONNECT DEVICE: The Producer shall provide, install, own and maintain the interconnection disconnect device required by Section B.3.b at a location readily accessible to the Utility. Such device shall normally be located near the Utility's meter or meters for sole operation by the Utility. The interconnection disconnect device and its precise location shall be specified by the Utility. At the Producer's option and request, the Utility will provide, install, own and maintain the disconnect device on the Utility's system as special facilities in accordance with Section F.

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[1] Detailed requirements are specified in the Utility's current operating, metering and equipment protection publications, as revised from time to time by the Utility and available to the Producer upon request. For a particular generator application, the Utility will furnish its specific control, protective and safety requirements to the Producer after the exact location of the generator has been agreed upon and the interconnection voltage level has been established.

[2] This is a transformer interconnected with no other Producers and serving no other Utility customers. Although the dedicated transformer is not a requirement for generators rated 10 kw or less, its installation is recommended by the Utility.

[3] This is a requirement for synchronous and other types of generators with stand-alone capability. For all such generators, the Utility will also require the installation of "reclose blocking" features on its system to block certain operations of the Utility's automatic line restoration equipment.

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RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

B. INTERCONNECTION FACILITIES (continued)

4. UTILITY SYSTEM ADDITIONS AND REINFORCEMENTS

a. Except as provided for in Section B.5, all additions to and reinforcements of th Utility's system necessary to interconnect with and receive power deliveries fro the Producer's generation will be provided, installed, owned and maintained by the Utility as special facilities in accordance with Section F. Such additions and reinforcements may include the installation of a Utility distribution or transmission line extension or the increase of capacity in the Utility's existin distribution or transmission lines. The Utility shall determine whether any suc additions or reinforcements shall include an increment of additional capacity for the Utility's use in furnishing service to its customers. If so, then the costs of providing, installing, owning and maintaining such additional capacity shall be borne by the Utility and/or its customers in accordance with the Utility's applicable tariffs on file with and authorized by the California Public Utilitie Commission (Commission).

b. The Producer shall advance to the Utility its estimated costs of performing a preliminary or detailed engineering study as may be reasonably required to identify any Producer related Utility system additions and reinforcements. Where such preliminary or detailed engineering study involves analysis of the Utility' transmission lines (60 kv and higher), the Utility shall complete its study within twelve calendar months of receiving all necessary plans and specification from the Producer.

5. PRODUCER-INSTALLED UTILITY-OWNED LINE EXTENSIONS: The Producer may at its option provide and install an extension of the Utility's distribution or transmission lines where required to complete the Producer's interconnection with the Utility. Such extension shall be installed by contractors approved by the Utility and in accordance with its design and specifications. The Producer shall pay the Utility its estimated costs of design, administration and inspection as may be reasonably required to ass such extension is installed in compliance with the Utility's requirements. Upon f inspection and acceptance by the Utility, the Producer shall transfer ownership of line extension to the Utility where thereafter it shall be owned and maintained as special facilities in accordance with Section F. This provision does not preclude th Producer from installing, owning and maintaining a distribution or transmission line extension as part of its other Producer-owned interconnection facilities.

6. COSTS OF FUTURE UTILITY SYSTEM ALTERATIONS: The Producer shall be responsible for the costs of only those future Utility system alterations which are directly related to the Producer's presence or necessary to maintain the Producer's interconnection in accordance with the Utility's applicable operating, metering and equipment publicatio in effect when the Producer and the Utility entered into a written form of power purchase agreement. Alterations made at the Producer's expense shall specifically exclude increases of existing line capacity necessary to accommodate the other Producers or Utility customers. Such alterations may, however, include relocation or undergrounding of the Utility's distribution or transmission lines as may be ordered by a governmental authority having jurisdiction.

7. ALLOCATION OF THE UTILITY'S EXISTING LINE CAPACITY: For two or more Producers seekin to use an existing line, a first come, first served approach shall be used. The firs Producer to request an interconnection shall have the right to use the existing line and shall incur no obligation for costs associated with future line upgrades needed to accommodate other Producers or customers. The Utility's power purchase agreement shall specify the date by which the Producer must begin construction. If that date passes and construction has not commenced, the Producer shall be given 30 days to correct the deficiency after receiving a reminder from the Utility that the construction start-up date has passed. If construction has not commenced after the 30-day corrective period, the Utility shall have the right to withdraw its commitment to the first Producer and offer the right to interconnect on the existing line to the next Producer in order. If two Producers establish the right of first-in-time simultaneously, the two Producers shall share the costs of any additional line upgrade necessary to facilitate their cumulative capacity requirements. Costs shall be share based on the relative proportion of capacity each Producer will add to the line.

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RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

C. ELECTRIC SERVICE FROM THE UTILITY: If the Producer requires regular, supplemental, interruptible or standby service from the Utility, the Producer shall enter into separate contractual arrangements with the Utility in accordance with the Utility's applicable electric tariffs on file with and authorized by the Commission.

D. OPERATION

1. PREPARALLEL INSPECTION: In accordance with Section A.7, the Utility will inspect the Producer's interconnection facilities prior to providing it with written authorization to commence parallel operation. Such inspection shall determine whether or not the Producer has installed certain control, protective and safety equipment to the Utility's specifications. Where the Producer's generation has a rated output in excess of 100 kw, the Producer shall pay the Utility its estimated costs of performing the inspection.

2. JURISDICTION OF THE UTILITY'S SYSTEM DISPATCHER: The Producer's generation while operating in parallel with the Utility's system is at all times under the jurisdiction of the Utility's system dispatcher. The system dispatcher shall normally delegate such control to the Utility's designated switching center.

3. COMMUNICATIONS: The Producer shall maintain telephone service from the local telephone company to the location of the Producer's generation. In the event such location is remote or unattended, telephone service shall be provided to the nearest building normally occupied by the Producer's generator operator. The Utility and the Producer shall maintain operating communications through the Utility's designated switching center.

4. GENERATOR LOG: The Producer shall at all times keep and maintain a detailed generator operations log. Such log shall include, but not be limited to, information on unit availability, maintenance outages, circuit breaker trip operations requiring manual reset and unusual events. The Utility shall have the right to review the Producer's log.

5. REPORTING ABNORMAL CONDITIONS: The Utility shall advise the Producer of abnormal conditions which the Utility has reason to believe could affect the Utility's operating conditions or procedures. The Producer shall keep the Utility similarly informed.

6. POWER FACTOR: The Producer shall furnish reactive power as may be reasonably required by the Utility.

    a. The Utility reserves the right to specify that generators with power factor control capability, including synchronous generators, be capable of operating continuously at any power factor between 95 percent leading (absorbing vars) and 90 percent lagging (producing vars) at any voltage level within ± 5.0 percent of rated voltage. For other types of generators with no inherent power factor control capability, the Utility reserves the right to specify the installation of capacitors by the Producer to correct generator output to near 95 percent leading power factor. The Utility may also require the installation of switched capacitors on its system to produce reactive support equivalent to that provided by operating a synchronous generator of the same size between 95 percent leading and 90 percent lagging power factor.
    b. Where either the Producer or the Utility determines that it is not practical for the Producer to furnish the Utility's required level of reactive power or when the Utility specifies switched capacitors in its system pursuant to Section D.6.a, the Utility will provide, install, own and maintain the necessary devices on its system in accordance with Section F.

E. INTERFERENCE WITH SERVICE AND COMMUNICATION FACILITIES

1. GENERAL: The Utility reserves the right to refuse to connect to any new equipment or to remain connected to any existing equipment of a size or character that may be detrimental to the Utility's operations or service to its customers.

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Advice Letter No. 1025-E
Decision No. 83-10-093

Issued By
W. M. Gallavan
Vice-President
Rates and Economic Analysis

Date Filed
Effective JUN 2 0
Resolution No.

RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

E. INTERFERENCE WITH SERVICE AND COMMUNICATION FACILITIES (continued)

2. The Producer shall not operate equipment that superimposes upon the Utility's system voltage or current which causes interference with the Utility's operations, service t the Utility's customers or interference to communication facilities. If the Producer causes service interference to others, the Producer must diligently pursue and take corrective action at the Producer's expense after being given notice and reasonable time to do so by the Utility. If the Producer does not take timely corrective action or continues to operate the equipment causing the interference without restriction or limit, the Utility may, without liability, disconnect the Producer's equipment from the Utility's system until a suitable permanent solution provided by the Producer is operational at the Producer's expense.

F. SPECIAL FACILITIES

1. Where the Producer requests the Utility to furnish interconnection facilities or where it is necessary to make additions to or reinforcements of the Utility's system and th Utility agrees to do so, such facilities shall be deemed to be special facilities and the costs thereof shall be borne by the Producer, including such continuing ownership costs as may be applicable.

2. Special facilities are (a) those facilities installed at the Producer's request which the Utility does not normally furnish under its tariff schedules, or (b) a prorata portion of existing facilities requested by the Producer, allocated for the sole use of such Producer, which would not normally be allocated for such sole use. Unless otherwise provided by the Utility's filed tariff schedules, special facilities will be installed, owned and maintained or allocated by the Utility as an accommodation to th Producer only if acceptable for operation by the Utility and the reliability of service to the Utility's customers is not impaired.

3. Special Facilities will be furnished under the terms and conditions of the Utility "Agreement for Installation or Allocation of Special Facilities for Parallel Opera of Nonutility-owned Generation and/or Electrical Standby Service" (Form 79-280, effective June 1984) and its Appendix A, "Detail of Special Facilities Charges" (Form 79-702, effective June 1984). Prior to the Producer signing such an agreement, the Utility shall provide the Producer with a breakdown of special facilities costs i a form having detail sufficient for the information to be reasonably understood by th Producer. The special facilities agreement will include, but is not limited to, a binding quotation of charges to the Producer and the following general terms and conditions:

   a. Where facilities are installed by the Utility for the Producer's use as special facilities, the Producer shall advance to the Utility its estimated installed cost of the special facilities. The amount advanced is subject to the monthly ownership charge applicable to customer-financed special facilities as set forth in Section I of the Utility's Rule No. 2.

   b. At the Producer's option, and where such Producer's generation is a qualifying facility* and the Producer has established credit worthiness to the Utility's satisfaction, the Utility shall finance those special facilities it deems to be removable and reusable equipment. Such equipment shall include, but not be limited to, transformation, disconnection and metering equipment.

   c. Existing facilities allocated for the Producer's use as special facilities and removable and reusable equipment financed by the Utility in accordance with Section F.3.b are subject to the monthly ownership charge applicable to Utility-financed special facilities as set forth in Section I of Rule 2.

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*A qualifying facility is one which meets the requirements established by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

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RULE NO. 21 -- NONUTILITY-OWNED PARALLEL GENERATION (Cont'd.)

F. SPECIAL FACILITIES (continued)

d. Where the Producer elects to install and deed to the Utility an extension of the Utility's distribution or transmission lines for use as special facilities in accordance with Section B.5, the Utility's estimate of the installed cost of such extension shall be subject to the monthly ownership charge applicable to customer-financed special facilities as set forth in Section I of the Rule No. 2.

4. Where payment or collection of continuing monthly ownership charges is not practicable, the Producer shall be required to make an equivalent one-time payment in lieu of such monthly charges.

5. Costs of special facilities borne by the Producer may be subject to downward adjustment when such special facilities are used to furnish permanent service to a customer of the Utility. This adjustment will be based upon the extension allowance or other such customer allowance which the Utility would have utilized under its then applicable tariffs if the special facilities did not otherwise exist. In no event shall such adjustment exceed the original installed cost of that portion of the special facilities used to serve a new customer. An adjustment, where applicable, will consist of a refund applied to the Producer's initial payment for special facilities and/or a corresponding reduction of the ownership charge.

G. EXCEPTIONAL CASES: Where the application of this rule appears impractical or unjust, the Producer may refer the matter to the Commission for special ruling or for the approval of special conditions.

H. INCORPORATION INTO POWER PURCHASE AGREEMENTS: Pursuant to Decision No. 83-10-093, if in accordance with Section A.4 the Producer enters into a written form of power purchase agreement with Utility, a copy of the Rule No. 21 in effect on the date of execution will be appended to, and incorporated by reference into, such power purchase agreement. The Rule appended to such power purchase agreement shall then be applicable for the term of the Producer's power purchase agreement with the Utility. Subsequent revisions to this rule shall not be incorporated into the rule appended to such power purchase agreement.

Advice Letter No. 1025-E
Decision No. 83-10-093

Issued By
W. M. Gallavan
Vice-President
Rates and Economic Analysis

Date Filed MAY 21
Effective JUN 2
Resolution No. ____

79-280 (Rev 10/84)
Region
Applicant
Construction Accounting
Accounting Operations
Commercial

PACIFIC GAS AND ELECTRIC COMPANY
AGREEMENT FOR INSTALLATION OR ALLOCATION OF SPECIAL FACILITIES FOR PARALLEL OPERATION OF NONUTILITY-OWNED GENERATION AND/OR ELECTRICAL STANDBY SERVICE
(Electric Rules Nos. 2 and 21)

At the request of ______________________________ (Applicant), PACIFIC GAS AND ELECTRIC COMPANY (PGandE) hereby agrees to furnish at Applicant's expense within a reasonable time certain facilities consisting of ______________________________ (Special Facilities). Special Facilities are expected to be necessary on or about ______________ for the interconnect of Applicant's electric generating plant with PGandE's system and/or PGandE's delivery of electrical standby serv Applicant's premises at ______________________________, County of ______________ State of California.

1. This Agreement includes Appendix A, Detail of Special Facilities Charges, which is attached and incorporated herein by reference. Appendix A may be revised or superseded by mutual written agreement and withou formal amendment of the remainder of this Agreement.

2. Applicant shall pay PGandE, on demand prior to commencement of any work by PGandE, an initial charg equal to the sum of (a) plus (b) below, the amounts of which are specified in Appendix A:

(a) an ADVANCE equal to PGandE's estimated installed cost of Special Facilities which are finance y Applicant including, in lieu of cash payment, a credit for that portion of Special Facilities furnished and deede o PGandE by Applicant; and

(b) a REARRANGEMENT CHARGE which is equal to PGandE's estimated cost of rearranging existing faci to accommodate the installation of Special Facilities.

3. Applicant also shall pay PGandE any applicable monthly rates and charges for service under PGandE's tariff schedules plus an ownership charge, either (a) or (b) below as specified in Appendix A, namely:

(a) COST OF OWNERSHIP CHARGE representing PGandE's continuing monthly cost of financing (if applic owning and maintaining Special Facilities; or

(b) an EQUIVALENT ONE-TIME CHARGE which is equal to the present worth of the monthly COST OF OWNER CHARGE in perpetuity. The COST OF OWNERSHIP CHARGE shall commence on the date Special Facilities are first available for Applicant's use, as such date is established in PGandE's records. PGandE will notify Applicant, in writing, commencement date. The EQUIVALENT ONE-TIME CHARGE (if applicable) shall be payable by Applicant to PGandE on

4. The ownership charge set forth in paragraphs 3(a) or 3(b) herein is determined in accordance wi applicable percentage rates established in the Special Facilities section of PGandE's electric Rule No. 2, copy attached. Should the California Public Utilities Commission (Commission) subsequently authorize higher or lower percentage rates, the monthly COST OF OWNERSHIP CHARGE shall automatically increase or decrease without formal am to Appendix A as of the effective date of the Commission's authorization.

5. Where it is necessary to install Special Facilities on Applicant's premises, Applicant hereby grant PGandE:

(a) the right to make such installation on Applicant's premises along the shortest practical route thereon with sufficient legal clearance from all structures now or hereafter erected on Applicant's premises; and

(b) the right of ingress to and egress from Applicant's premises at all reasonable hours for any purposes reasonably connected with the operation and maintenance of Special Facilities.

6. Where formal rights of way or easements are required on or over property of Applicant or the property others for the installation of Special Facilities, Applicant agrees that PGandE shall obtain them at Applicant's expense, or if Applicant and PGandE agree otherwise, Applicant shall obtain any necessary permanent rights of way easements, satisfactory to and without cost to PGandE.

7. PGandE shall not be responsible for any delay in completion of the installation of Special Facilities resulting from shortage of labor or materials, strike, labor disturbance, war, riot, weather conditions, governmen rule, regulation or order, including orders or judgments of any court or regulatory agency, delay in obtaining nec rights of way and easements, acts of God, or any other cause or condition beyond the control of PGandE, nor shall be liable for incidental, indirect, special, punitive, or consequential damages for any such delay. PGandE shall hav the right, if for one of the above reasons it is unable to obtain materials or labor for all of its construction requirements, to allocate materials and labor to construction projects which it deems, in its sole discretion, mos important to serve the needs of its customers, and any delay in construction hereunder resulting from such allocat shall be deemed to be a cause beyond PGandE's control. In any event, PGandE's total liability for any delay in the completion of the installation of Special Facilities shall not exceed the amount of Special Facilities charges paid b Applicant.

8. In the event that PGandE is prevented from completing the installation of Special Facilities for re beyond its control after twelve (12) months following the date of this Agreement, PGandE shall have the right supersede this Agreement subject to Applicant's election as provided below upon at least thirty (30) days' wri notice to Applicant and adjust any amounts paid or required to be paid by Applicant hereunder that may be due that portion of the Special Facilities then completed, if any, utilizing the estimated costs developed by PGan this agreement. Such a superseding agreement, if any, shall be in substantially the same form as this agreement, executed by both parties hereto, and shall provide that costs be allocated to the portion of the Special Facilities completed, if any, consistent with those costs estimated by PGandE for this agreement. If Applicant elects not to execute a superseding agreement, this agreement shall be terminated and the provisions of paragraph 11 herein shal applied to that portion of Special Facilities then completed, if any. Applicant also shall reimburse PGandE for a expenses it may have incurred for engineering, surveying, right of way acquisition and other work associated with the

9. If it becomes necessary for PGandE to alter, rearrange or make addition to Special Facilities in orde maintain parallel operation of Applicant's generation or electrical standby service to Applicant's premises, Applicant shall be notified, in writing, of such necessity and shall be given the option to either terminate this Agreement upon thirty (30) days' written notice to PGandE, or to pay to PGandE additional Special Facilities charges consisting of:

(a) a facility termination charge for that portion of Special Facilities which is being removed becaus of alteration, rearrangement or addition to Special Facilities. Such charge to be determined in the same manner as described in paragraph 11 herein; plus,

(b) an additional ADVANCE and/or REARRANGEMENT CHARGE, if any, for any new Special Facilities which shall be applied in the same manner as prescribed in paragraph 2 herein; plus,

(c) a revised monthly COST OF OWNERSHIP CHARGE or EQUIVALENT ONE-TIME CHARGE based on the estimated installed costs of all new and remaining Special Facilities. Such revised monthly COST OF OWNERSHIP CHARGE or EQUIVALENT ONE-TIME CHARGE shall be applied in the same manner as prescribed in paragraph 3 herein.

10. This Agreement shall become effective when executed by the parties hereto and, except as provided for i paragraphs 8 and 9 herein, shall remain in force until one of the following events occurs:

(a) a power purchase, parallel operation, electrical standby service or other form of agreement no longer exists between Applicant and PGandE which would occasion the need for Special Facilities; or

(b) the ownership of Special Facilities or any portion thereof is deeded to a public authority; or

(c) Applicant fails to pay the monthly COST OF OWNERSHIP CHARGE prescribed in this Agreement, if applicable.

Either party shall provide the other at least thirty (30) days' written notice of termination pursuant to this paragraph.

11. Upon termination of this Agreement for any reason:

(a) Applicant shall pay to PGandE on written demand (in addition to all other monies to which PGandE m be legally entitled by virtue of such termination) a facility termination charge defined as the estimated installed cost, plus the estimated removal cost less the estimated salvage value for any Special Facilities which can be removed all as determined by PGandE in accordance with its standard accounting practices. PGandE shall deduct from the facili termination charge the ADVANCE plus the unamortized balance of the EQUIVALENT ONE-TIME CHARGE previously paid, if any. If the ADVANCE paid plus the unamortized balance of the EQUIVALENT ONE-TIME CHARGE, if any, is greater than the facili termination charge, PGandE shall refund the difference, without interest, to Applicant; and

(b) PGandE shall be entitled to remove and shall have a reasonable time in which to remove any portion of the Special Facilities located on Applicant's premises; and

(c) PGandE may, at its option, alter, rearrange, convey or retain in place any portion of the Special Facilities located on other property off Applicant's premises. Where all or any portion of the Special Facilities located off Applicant's premises are retained in place in anticipation of providing permanent service to customers of PGandE, an equitable adjustment shall be made in the facility termination charge.

12. In the event any of the Special Facilities are used during the term of this agreement to provide permanent service to customers of PGandE, an adjustment shall be made in accordance with PGandE's electric Rule No. 21 copy attached.

13. Special Facilities shall at all times be the property of PGandE.

14. As provided in PGandE's electric Rule No. 14, copy attached, PGandE does not guarantee electrical stand service to be free from outages, interruptions or curtailments and the charges for Special Facilities represent PGandE cost associated with providing Special Facilities rather than for a guaranteed level of service or reliability.

15. Applicant may, with PGandE's written consent, assign this Agreement if the assignee thereof will agree writing to perform Applicant's obligations hereunder. Such assignment will be deemed to include, unless otherwise specified therein, all of Applicant's rights to any refunds which might become due upon discontinuance of the use of a Special Facilities.

16. This Agreement shall be subject to all of PGandE's applicable tariffs on file with and authorized by th Commission, and shall at all times be subject to such changes or modifications as the Commission may direct from time time in the exercise of its jurisdiction.

Dated this _________ day of _________________________, 19___.

PACIFIC GAS AND ELECTRIC COMPANY

____
(Applicant)

By: _____________________________

Title: ___________________________

Mailing
Address: _________________________

By: _____________________________

Manager,
Region ___________________________

Attachments: Electric Rule No. 2
Electric Rule No. 14

79-702 (6/84)
Region
Applicant
Construction Accounting
Accounting Operations
Commercial

Appendix A (Dated:
to the AGREEMENT FOR INSTALLATI
OR ALLOCATION OF SPECIAL FACILIT
FOR PARALLEL OPERATION OF NON
OWNED GENERATION AND/OR ELECT
STANDBY SERVICE (Dated:

DETAIL OF SPECIAL FACILITIES CHARGES

I. Applicability

The application of charges specified herein are pursuant to the provisions of this Agreement between ____________ (Applicant) and Pacific Gas and Electric Company (PGandE) and shall be a part th and in effect until superseded by mutual written agreement.

II. Initial Charge

A.	net cost of all Special Facilities	$ ________
B.	less the cost of "removable and reusable" Special Facilities which are provided, installed and financed by PGandE pursuant to Rule No. 21	$(________)
C.	ADVANCE	$ ________
D.	less PGandE's estimate of the cost of Special Facilities provided, installed and deeded to PGandE by Applicant (includes costs of design and administration by PGandE)	$(________)
E.	plus the cost of design, administration and inspection by PGandE of Special Facilities provided, installed and deeded to PGandE by Applicant	$ ________
F.	plus REARRANGEMENT CHARGE	$ ________
G.	Initial Charge	$ ________

III. Installed Cost of PGandE's Existing Facilities Allocated to Applicant's Use .... $ ________

IV. Monthly COST OF OWNERSHIP CHARGE

Special Facilities financed by:	Application base	Current percentage rate^2	Monthly Charge
A. Applicant	ADVANCE (II.C. above equals 1. plus 2. below)		
	1. cost of distribution facilities.. $ ________		
	less allowance for existing facilities........ $(________)^3		
	net amount........ $ ________	x ________/mo.	= $ ________/mo.
	2. cost of transmission facilities.. $ ________		
	less allowance for existing facilities........ $(________)^3		
	net amount........ $ ________	x ________/mo.	= $ ________/
B. PGandE	"removable and reusable" Special Facilities (II.B. above equals 3. plus 4. below)		
	3. distribution facilities........ $ ________	x ________/mo.	= $ ________/
	4. transmission facilities........ $ ________	x ________/mo.	= $ ________/mo.
C. PGandE	existing facilities allocated as Special Facilities (III. above equals 5. plus 6. below)		
	5. distribution facilities........ $ ________	x ________/mo.	= $ ________
	6. transmission facilities........ $ ________	x ________/mo.	= $ ________/

D. Monthly COST OF OWNERSHIP CHARGE .... $ ________/

V. EQUIVALENT ONE-TIME CHARGE (in lieu of monthly COST OF OWNERSHIP CHARGE); check ☐ if applicable

$ _______/mo. (line IV.D.) x 12 mo. x ____ (present worth factor)........................... $ _______

---

1 Used in calculation of the monthly COST OF OWNERSHIP CHARGE or EQUIVALENT ONE-TIME CHARGE.

2 This percentage rate is set forth in Section I of PGandE's current electric Rule No. 2 and is subject to change upo authorization by the California Public Utilities Commission.

3 Where Special Facilities displace PGandE's existing facilities, this allowance assures the exclusion of PGandE's existing ownership costs from Applicant's monthly COST OF OWNERSHIP CHARGE or EQUIVALENT ONE-TIME CHARGE.

Complete the following section only in conjunction with revision of this Appendix

This Appendix A supersedes Appendix A dated __________, 19__. The changes hereon are hereby agreed to b both parties on this __________day of __________________, 19__.

PACIFIC GAS AND ELECTRIC COMP

____
(Applicant)

By: __________________

Title: __________________

By: __________________

Manager, __________________
Region

F-2 POINT OF DELIVERY LOCATION SKETCH

---

1 To be determined upon execution of the Special Facilities Agreement for the Facility.

F-3 INTERCONNECTION FACILITIES FOR WHICH SELLER IS RESPONSIBLE

---

1 To be determined upon execution of the Special Facilities Agreement for the Facility.

ORIGINAL PG&E STANDARD OFFERS AT TIME OF CONTRACTS

Pacific Gas and Electric Company
Mission Trail Region

111 Almaden Boulevard
P.O. Box 15005
San Jose, CA 95115-0005
408/280-1212

LEY

July 24, 1991

7/25 SWK w/A
RDW

P

Mr. Stan Kaut
Santa Clara Valley Water District
5750 Almaden Expressway
San Jose, California 95118

Dear Stan,

Enclosed is the summary of PG&E Standard Offers for Power Purchases and Qualifying Facilities that you requested.

If you have any questions or would like more information, please call me at (408) 282-7439.

Sincerely,

David Head
David Head
Account Representative

DJH:cec

Enclosure

SO# 1 AS DELIVERED CAPACITY AND ENERG
2 FIRM CAPACITY AND ENERGY
3 AS DELIVERED CAPACITY AND ENERGY FOR QF's 100 KW AND LESS
4 LONG TERM OFFER

SUMMARY OF PGandE STANDARD OFFERS FOR POWER PURCHASES FROM QUALIFYING FACILITIES - 1984

INTRODUCTION

This summary is an overview of PGandE's four standard offers for power purchases from cogeneration and small power production facilities which meet the qualifying facility requirements of the Public Utility Regulatory Policies Act of 1978 (QFs). It summarizes some of the general terms and conditions of the standard offers as well as the various capacity and energy payment options available. A full understanding of all the rights and obligations of the contracting parties under the various options can only be obtained by a thorough review of the contracts themselves and this summary should not be used as a substitute for such review. It is offered only to aid potential QFs in their initial understanding of the various power purchase agreement options available from PGandE.

PGandE's standard offer forms are subject to change from time to time pursuant to orders of the California Public Utilities Commission.

GENERAL PROVISIONS

The following rights and obligations are common to all four of PGandE's Standard Offers:

- Seller is responsible for all aspects and costs associated with design, construction and operation of the generating facility.

9/5/84

- Interconnection facilities are governed by Electric Rule 21. Seller must pay the cost of reinforcements and additions to PGandE's system necessary to accept power deliveries. These costs include a continuing monthly cost of ownership charge. Seller has the option to install, own and operate new interconnection facilities such as line extensions, or have PGandE provide them under a Special Facilities Agreement.

- Seller may sell all the power output (net of station load) to PGandE on a "net energy output" basis or if there is an electric load at the site, other than the plant station load, use part of the generation to meet that load and sell the excess on a "surplus energy output" basis.

- Payments for power are made on a monthly basis.

- PGandE is allowed to curtail or reduce power deliveries for emergencies and when necessary to perform work on its equipment.

- Insurance requirements vary depending upon the size of the facility.

STANDARD OFFER NO. 1

AS-DELIVERED CAPACITY AND ENERGY

- Seller receives full short run avoided operating costs for energy delivered.
- Seller receives time-differentiated prices determined from time to time by the CPUC for "as-delivered capacity." This will likely be based on the one-year shortage cost of capacity.
- PGandE is allowed to curtail QFs 1 MW or greater for negative avoided cost and reduce the energy price during hydro spill conditions at PGandE plants. (Negative avoided cost and hydro spill are defined by CPUC.)
- Seller is not required to deliver power at any particular time or at any given level.
- Seller may terminate the contract at any time.

9/5/84

STANDARD OFFER NO. 2

FIRM CAPACITY AND ENERGY

- Seller shall receive full short run avoided operating costs for energy delivered.

- The capacity price is levelized over the term of the agreement.

- PGandE is allowed to curtail QFs 1 MW or greater for negative avoided cost and reduce the energy price during hydro spill conditions at PGandE plants. (Negative avoided cost and hydro spill are defined by CPUC.)

- Two methods for firm capacity payments:

Option 1 - 1/12 of the product of the contract capacity price, the contract capacity, the appropriate capacity loss adjustment factor, and the appropriate performance bonus factor.

Option 2 - Product of a "Period Price Factor" (which includes two periods, summer and winter), the "Monthly Delivered Capacity" (based on the actual power deliveries during all on-peak and partial peak hours), the capacity loss adjustment factor, and the performance bonus factor.

- Capacity must be available or delivered during all on-peak hours in June, July, and August subject to a 20% forced outage allowance. Option 1 requires project dispatchability throughout the year.

- Firm capacity rating for hydro projects is based on the average of the five driest years identified in a theoretical operation study. It may be adjusted up or down if appropriate.

- If the contract is terminated or the capacity level is reduced, PGandE will be compensated by the developer. Termination costs will vary depending on the notice given PGandE, if any, and the number of years left in the contract.

9/5/84

STANDARD OFFER NO. 3

AS-DELIVERED CAPACITY AND ENERGY FOR QFs 100 kW AND LESS

- Seller will receive full short run avoided operating costs for energy delivered.
- Seller will receive prices authorized from time to time by the CPUC for as-delivered capacity.
- PGandE will install standard watt meter at its own expense.

STANDARD OFFER NO. 4

LONG-TERM OFFER

ENERGY PAYMENT OPTIONS

- Option 1 - Forecasted Energy Prices.
  - A set of time-differentiated energy prices is contractually established for each year not to exceed the first 10 years of operation. (The "fixed price period.")
  - Fixed price period is 1/3 of contract term for term of 15-19 years; 10 years for terms of 20 years or more.
  - The yearly escalating energy prices are based on a compromise that was reached during the CPUC ordered Settlement Conference which led to the development of the offer. (They do not represent PGandE's current forecast of avoided costs.)
  - Seller must begin energy deliveries within five years of contract execution, or the contract terminates.
  - Seller selects energy payments based on a % actual/% forecasted prices in 20% increments.
  - Seller may switch to Option 2 90 days prior to operation, but must maintain percentages originally selected.
  - Oil or gas-fired cogenerators are restricted to 20% of forecasted prices and 80% actual prices.
- Option 2 - Levelized Energy Prices
  - A set of time-differentiated energy prices which are the same for each year of the fixed price period. Prices are a levelization of the prices of Option 1, and available for up to the first 10 years of operation.
  - Fixed price period is 1/3 of contract term for terms of 15-19 years; 10 years for terms of 20 years or more.

- Seller must begin energy deliveries within five years of contract execution or the contract terminates.

- Seller selects % actual/% levelized payment structure, in 20% increments.

- Damages recoverable if Seller fails to meet certain energy delivery levels during last part of fixed price period.

- Termination damages if terminated prior to end of levelization period.

- Seller must post security during the fixed price period to cover the potential damages for termination or failure to meet performance requirements.

- Seller may switch to Option 1 90 days prior to operation but must maintain percentages originally selected.

- Not available to oil/gas cogenerators.

- Option 3 – Incremental Energy Rate Factors

  - Monthly energy payments will be made based on published avoided energy cost, with an annual adjustment based on a schedule of energy rate factors and a symmetrical band width specified by Seller.

  - Annual adjustment to payments in accordance with energy rate factor schedule.

  - Seller selects number of years this energy option will be in effect, but it cannot extend beyond the end of 1998.

CAPACITY PAYMENT OPTIONS

- Firm – Payments in accordance with Option 2 of Standard Offer No. 2. Deliveries in excess of firm capacity will be paid for on an as-delivered capacity basis (except for hydro facilities).

- As-Delivered - Seller selects as-delivered capacity prices as published from time to time, or a forecast (up to 10 years) of shortage costs. For forecast option, there will be a floor on the as-delivered capacity price for remaining years of contract.

CURTAILMENT OPTIONS

- Option A - Hydro Spill and Negative Avoided Cost. Concept as in Standard Offer Nos. 1 and 2.
- Option B - Adjusted Price Period. Up to 1,000 off-peak hours of real time pricing when PGandE has non-oil and gas units on the margin. Seller's energy payments in remaining off-peak hours will be adjusted upward.

9/5/84

Pacific Gas and Electric Company

77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
415/973-7000

1st AMEND
NEVER
EXECUTED

December 2, 1998

Mr. Stan Kaut
5750 Almaden Expressway
San Jose, CA 95118

Re: Santa Clara Valley Water District - First Amendment to Power Purchase Agreement (PG&E Log No. 08H013)

Dear Stan:

Per your request, enclosed is a first amendment to the Power Purchase Agreement ("PPA") between Santa Clara Valley Water District ("SCVWD") and PG&E (the "Amendment"). At the time of execution, SCVWD elected to provide 500 kw of firm capacity but did not perform a firm capacity demonstration test as required by the PPA prior to commencement of firm capacity payments. PG&E and SCVWD have agreed to amend SCVWD's PPA capacity election to provide for 500 kw of as-delivered capacity pursuant to as-delivered capacity payment option 1 (see Appendix D) of the PPA.

The Amendment also acknowledges the fact that SCVWD has been paid fixed forecasted energy prices since initial energy deliveries on December 1, 1988, and the applicability of these fixed energy prices expired effective November 30, 1998. Additionally, the Amendment acknowledges that the PPA will expire by its own terms as of November 30, 2018.

Enclosed are two originals of the Amendment for your signature. Please return both signed originals to me at Mail Code B13E of the letterhead address. I will then obtain PG&E's counter signatures. Once the Amendment is fully executed, I will return one original to you for your files. If you have any questions, please don't hesitate to call me at (415) 973-1065.

Sincerely,

Donna Rajewski

Donna Rajewski
Resource Analyst
Utility Electric Supply

Enclosures

September 2, 1998

Ms. Donna Rajewski
Pacific Gas and Electric Company
Mail Code B13E
P.O. Box 770000
San Francisco, CA 94177

Dear Ms. Rajewski:

This letter is to confirm Santa Clara Valley Water District's (District) conference call with Pacific Gas and Electric (PG&E) on July 14, 1998. During our discussion it was confirmed that the District has a 30-year agreement with PG&E beginning April 16, 1985, the date of execution of its Power Purchase Agreement. During the time of execution, the District selected a firm capacity commitment of 500 kw but during the first 10 years of operation has not completed the required firm capacity demonstration test and thus has not received capacity payments. PG&E's records show that the District has been paid the fixed forecasted energy price which will expire on November 30, 1998.

Based on our discussion, the District would like to provide PG&E with a written request to amend the PPA to as-delivered capacity payment Option 1 pricing for the remainder of the PPA term and is willing to acknowledge that the PPA term runs 30 years from December 1, 1988, expiring on November 30, 2018.

Sincerely,

ORIGINAL SIGNED BY

Stan W. Kaut
Senior Engineer
Project Development

cc: W. Wadlow, D. Chesterman, D. Wentzel, D. Erba, M. Klemencic, C. Coody, J. Aguilera, File

SAK:mt:CR0901c

FIRST AMENDMENT

TO THE POWER PURCHASE AGREEMENT

BETWEEN

SANTA CLARA VALLEY WATER DISTRICT

AND

PACIFIC GAS AND ELECTRIC COMPANY
(LOG NO. 08H013)

Recitals

A. Santa Clara Valley Water District ("Seller") on April 16, 1985, and Pacific Gas and Electric Company (PG&E"), on April 17, 1985, executed a Power Purchase Agreement (the "PPA") for the purchase of energy and firm capacity from Seller's 800 kw (nameplate rating) hydroelectric facility located at Anderson Dam, near Morgan Hill, Santa Clara County, California (the "Facility").

B. The Facility made its initial energy deliveries on December 1, 1988, and has since regularly produced power for sale to PG&E.

C. At the time of execution of the PPA, Seller selected a firm capacity commitment of 500 kw but during the first 10 years of operation did not complete the firm capacity demonstration test as required by the PPA prior to commencement of firm capacity payments and thus has not received such capacity payments under the PPA.

D. Seller has been paid fixed forecasted energy prices pursuant to Table B-1 of PPA Appendix B and throughout its fixed price period (as fixed price period is defined in Appendix A, Section A-1, of the PPA) which period began with initial energy deliveries on December 1, 1988, and which period the Parties acknowledge expired on November 30, 1998.

E. Seller and PG&E have agreed to amend the PPA to delete the term that currently provides for payment of up to the 500 kw of firm capacity and to substitute in its stead a provision that provides for payment for up to 500 kw of as-delivered capacity pursuant to the terms set forth in Appendix D of the PPA, As-Delivered Capacity Payment Option 1.

Agreement

THEREFORE, for good and valuable consideration, receipt of which is hereby acknowledged, effective December 1, 1998, Seller and PG&E hereby agree to amend the PPA (the "First Amendment") as follows:

1. Article 5, CAPACITY ELECTION AND CAPACITY PRICE, on page 10, line 7 through 25 shall be amended as follows:

   The provisions on page 10, lines 13 through 25 are deleted from the PPA and lines 13 through 19 shall have no further force or effect. In their place the following term is hereby substituted:

   " X   As-delivered capacity with payment determined in accordance with As-Delivered Capacity Payment Option 1 set forth in Appendix D. Such as-delivered capacity payments shall not exceed 500 kw."

2. Article 12, TERM OF AGREEMENT, on page 13, line 19 through page 14, line 2 shall be amended as follows:

   The provisions on page 13, line 21 through page 14, line 2 are deleted. In their place the following term is hereby substituted.

   "This Agreement shall be binding upon execution and remain in effect thereafter for 30 years commencing on the date of initial energy deliveries, December 1, 1988, and terminating on November 30, 2018."

3. Seller acknowledges that PG&E's administration of capacity payments, or lack thereof, prior to the effective date of this First Amendment were proper and correct. Seller hereby waives any claim for payment for capacity delivered prior to the effective date of this First Amendment. By this waiver, Seller expressly waives all rights under California Civil Code Section 1542, which provides as follows:

   > A GENERAL RELEASE DOES NOT EXTEND TO CLAIMS WHICH THE CREDITOR DOES NOT KNOW OR SUSPECT TO EXIST IN HIS FAVOR AT THE TIME OF EXECUTING THE RELEASE, WHICH IF KNOWN BY HIM MUST HAVE MATERIALLY AFFECTED HIS SETTLEMENT WITH THE DEBTOR.

   Seller, being aware of such code section, hereby expressly waives any rights it may have thereunder, as well as under any other statutes or common law principles of similar effect.

In WITNESS WHEREOF, Seller and PG&E have caused this First Amendment to be executed by their duly authorized representatives.

SANTA CLARA VALLEY
WATER DISTRICT

By:______________________

Name:______________________

Title:______________________

Date:______________________

PACIFIC GAS AND ELECTRIC
COMPANY

By:______________________

Name:______________________

Title:______________________

Date:______________________

FIRST AMENDMENT

TO THE POWER PURCHASE AGREEMENT

BETWEEN

SANTA CLARA VALLEY WATER DISTRICT

AND

PACIFIC GAS AND ELECTRIC COMPANY
(LOG NO. 08H013)

Recitals

A. Santa Clara Valley Water District ("Seller") on April 16, 1985, and Pacific Gas and Electric Company (PG&E"), on April 17, 1985, executed a Power Purchase Agreement (the "PPA") for the purchase of energy and firm capacity from Seller's 800 kw (nameplate rating) hydroelectric facility located at Anderson Dam, near Morgan Hill, Santa Clara County, California (the "Facility").

B. The Facility made its initial energy deliveries on December 1, 1988, and has since regularly produced power for sale to PG&E.

C. At the time of execution of the PPA, Seller selected a firm capacity commitment of 500 kw but during the first 10 years of operation did not complete the firm capacity demonstration test as required by the PPA prior to commencement of firm capacity payments and thus has not received such capacity payments under the PPA.

D. Seller has been paid fixed forecasted energy prices pursuant to Table B-1 of PPA Appendix B and throughout its fixed price period (as fixed price period is defined in Appendix A, Section A-1, of the PPA) which period began with initial energy deliveries on December 1, 1988, and which period the Parties acknowledge expired on November 30, 1998.

E. Seller and PG&E have agreed to amend the PPA to delete the term that currently provides for payment of up to the 500 kw of firm capacity and to substitute in its stead a provision that provides for payment for up to 500 kw of as-delivered capacity pursuant to the terms set forth in Appendix D of the PPA, As-Delivered Capacity Payment Option 1.

Agreement

THEREFORE, for good and valuable consideration, receipt of which is hereby acknowledged, effective December 1, 1998, Seller and PG&E hereby agree to amend the PPA (the "First Amendment") as follows:

1. Article 5, CAPACITY ELECTION AND CAPACITY PRICE, on page 10, line 7 through 25 shall be amended as follows:

   The provisions on page 10, lines 13 through 25 are deleted from the PPA and lines 13 through 19 shall have no further force or effect. In their place the following term is hereby substituted:

   " X   As-delivered capacity with payment determined in accordance with As-Delivered Capacity Payment Option 1 set forth in Appendix D. Such as-delivered capacity payments shall not exceed 500 kw."

2. Article 12, TERM OF AGREEMENT, on page 13, line 19 through page 14, line 2 shall be amended as follows:

   The provisions on page 13, line 21 through page 14, line 2 are deleted. In their place the following term is hereby substituted.

   "This Agreement shall be binding upon execution and remain in effect thereafter for 30 years commencing on the date of initial energy deliveries, December 1, 1988, and terminating on November 30, 2018."

3. Seller acknowledges that PG&E's administration of capacity payments, or lack thereof, prior to the effective date of this First Amendment were proper and correct. Seller hereby waives any claim for payment for capacity delivered prior to the effective date of this First Amendment. By this waiver, Seller expressly waives all rights under California Civil Code Section 1542, which provides as follows:

   > A GENERAL RELEASE DOES NOT EXTEND TO CLAIMS WHICH THE CREDITOR DOES NOT KNOW OR SUSPECT TO EXIST IN HIS FAVOR AT THE TIME OF EXECUTING THE RELEASE, WHICH IF KNOWN BY HIM MUST HAVE MATERIALLY AFFECTED HIS SETTLEMENT WITH THE DEBTOR.

   Seller, being aware of such code section, hereby expressly waives any rights it may have thereunder, as well as under any other statutes or common law principles of similar effect.

In WITNESS WHEREOF, Seller and PG&E have caused this First Amendment to be executed by their duly authorized representatives.

SANTA CLARA VALLEY WATER DISTRICT	PACIFIC GAS AND ELECTRIC COMPANY
By:________________________	By: ________________________
Name:________________________	Name: ________________________
Title: ________________________	Title: ________________________
Date: ________________________	Date: ________________________

Appendix

A. Executive Summary
B. Report
  1. Physical Feasibility
  2. Coincident Energy Demand
  3. Transmission Options and Fatal Flaws
  4. Revenue Options and Fatal Flaws
  5. Incentives and Funding Options
  6. Partnership Options
  7. Potential Legal and Regulatory Flaws
C. Appendix

Major Section Elements:

- **A key element of this evaluation was to look back at the 25-year history of hydropower evaluations at District sites. As a result of this "look back" a Time Line of Prior Reports was developed in order to review generation potential and recommendations. This time line follows:**

Time Line of Prior Reports

SCVWD Hydroelectric Re-evaluation

When	Report	Which Site	Energy (million kWh)/Year	RECOMMENDATION	CONCLUSION	ACTION
1978	#1	· Anderson	2.15	Wheeling Necc. For $ effectiveness-Hold/Revisit		
		· Coyote	1.26	Wheeling Necc. For $ effectiveness-Hold/Revisit		
		· Maple Ave	5.08	Pending future SC Conduit	Recommended (future)	
1980	#2	· Calero	2.94	modulation Calero pipeline to Almaden Valley Pipeline warrants study		
1981	#3	· Anderson	4.62	Warrants study		
		· Calero	4.43	Warrants study		
		· Lexington	2.46	Warrants study		
		· Coyote	1	Warrants study		
		· Stevens creek	0.42	Hold/revisit		
		· Guadalupe	0.35	Hold/revisit		
		· Almaden	0.23	Hold/Revisit		
1982	#4	· Anderson	4.62 (no change)	feasible-proceed with study		
		· Calero	4.43 (no change)	feasible-proceed with study		
		· Coyote	1.26	Cautioned-proceed with study		
		· Lexington	2.46 (no change)	Cautioned-proceed with study		
1983	#5, #6, #7	· Calero	2.93	Adjusted, well developed model.	Highly Recommended	Prelim Environmental assessment, negative declaration completed for Calero and Anderson. Preliminary FERC permits are pulled on all district dams
		· Coyote	1.05	Flow constraints	Marginal technical feasibility	
		· Lexington	1.64		Not feasible at 'current' rates	
1983	#8	· Kirk Turnout	2.06	Warrants study		
1983	#9	· Anderson	4.17	Detailed confirmation	Highly Recommended	
1984	#10	· Calero	2.93	Detailed confirmation	Highly Recommended	Environmental assessment and negative declaration for Kirk/Page turnouts as well as a
1984	#11, #12	· Kirk/Page	3.37	Detailed basis of design for Kirk/Page (1987)		
1988, March	#13	· Kirk/Page	3.2-3.5	Wheeling Necc. For $ effectiveness-Hold/Revisit Operational Parameters fleshed out, technically feasible but with inconsistent annual energy		Anderson In service
1992	#14	· Anderson	2.89	Early performance suffered dry first years, overstated economic model		
		· Calero	2.93 (no change)	SO-1 rates negate previously established basis	Still recommended (Investigate Rates)	
		· Kirk/Page	2.06 (no change)	SO-1 rates negate previously established basis	Still recommended (Investigate Rates)	

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